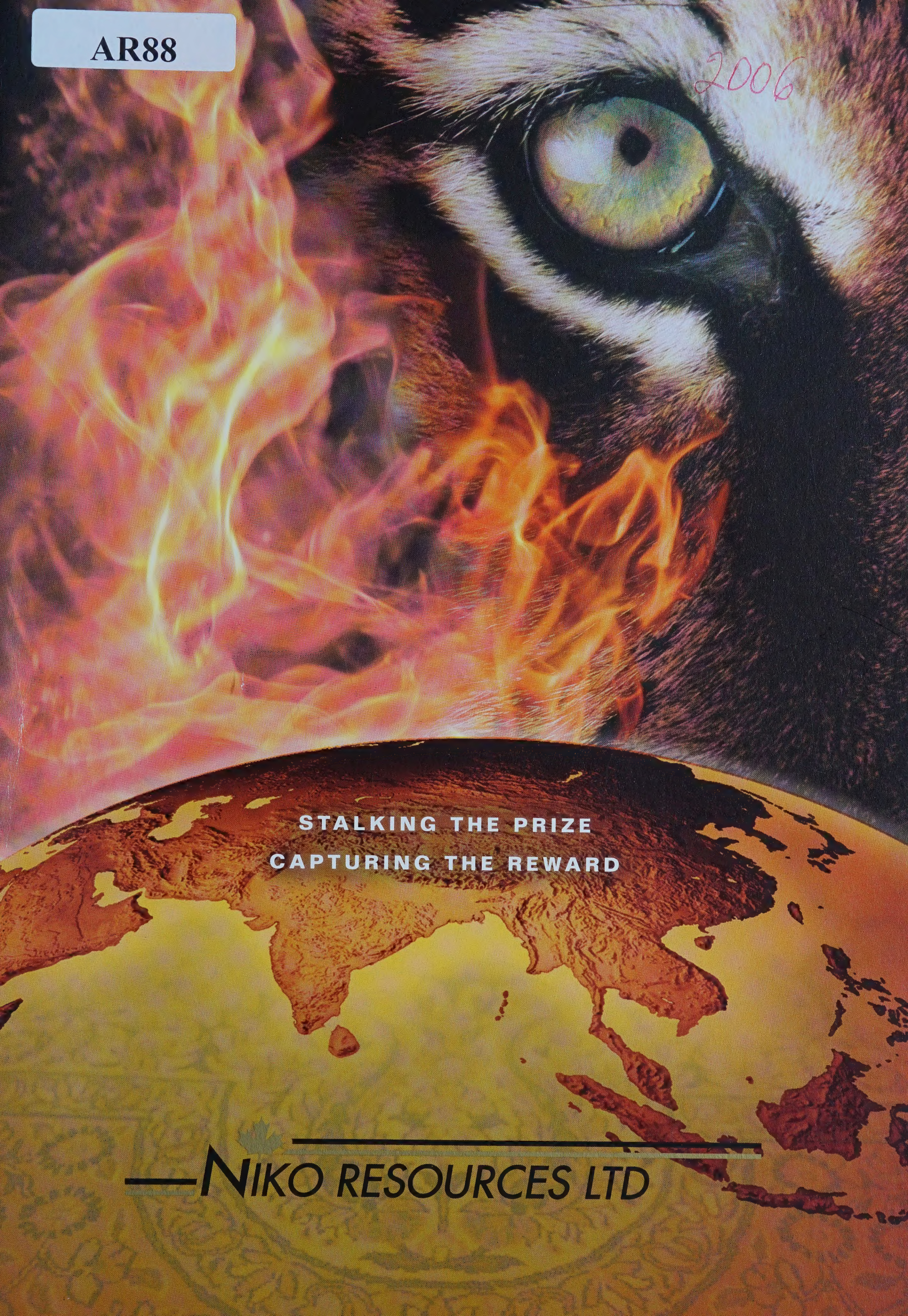
2006


STALKING THE PRIZE
CAPTURING THE REWARD
NIKO RESOURCES LTD

PERFORMANCE HIGHLIGHTS

YEAR ENDED MARCH 31	2006	2005	Percent Change
FINANCIAL ($ thousands, except per share amounts)			
Petroleum and natural gas sales	**121,168**	107,850	12
Funds from operations	**67,627**	87,393	(23)
Per share diluted ($)	**1.75**	2.39	(26)
Net income (loss)	**(4,352)**	74,222	(106)
Per share diluted ($)	**(0.11)**	2.03	(105)
Capital expenditures	**135,236**	119,105	14
Total assets	**517,258**	480,714	8
Shareholders' equity	**413,687**	413,544	0
Weighted average common shares outstanding	**38,336**	35,657	8
Common shares outstanding			
Basic (thousands)	**38,533**	38,287	1
Diluted (thousands)	**41,845**	40,266	4

OPERATIONS	2006	2005	Percent Change
Average daily production			
Oils (bbls/day)	**83**	57	46
Natural gas (mmcf/day)	**80**	61	31
Total combined (boe/day)	**13,412**	10,303	30
Revenues, royalties and operating costs			
Gross revenue received ($/boe)	**24.75**	28.68	(14)
Royalties ($/boe)	**(3.56)**	(4.40)	(19)
Profit petroleum ($/boe)	**(2.42)**	(2.41)	–
Operating costs ($/boe)	**(1.91)**	(2.26)	(15)
Operating netback ($/boe)	**16.86**	19.61	(14)
Net undeveloped land (square kilometres)			
India [2]	**5,227**	1,712	205
Bangladesh	**4,422**	4,422	–
Drilling activity			
Gross wells	**11**	21	(48)
Net wells	**3.2**	8.3	(61)
Net reserves (proved plus probable) [3]			
Oil (mbbls) [4]	**247**	194	27
Natural gas (mmcf) [4]	**539,519**	531,967	1
Natural gas liquids (mbbls)	**9**	18	(50)
Future net income after tax (PV 10% discounted) [3] [5]			
Proved ($000s)	**580,869**	450,340	29
Proved plus probable ($000s)	**934,625**	773,143	21

The Company's activities are carried out primarily in U.S. dollars as well as the currencies of each country in which the Company operates. The Company reports financial results in Canadian dollars.

The selected financial information presented above is prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP), except for funds from operations and funds from operations per share, which are used by the Company to analyze the results of operations and liquidity. By examining funds from operations, the Company is able to determine its ability to fund future capital projects and investments. Funds from operations is calculated as cash flows prior to the change in non-cash working capital related to operating activities. Funds from operations is not an alternative to cash flow from operating activities as determined in accordance with Canadian GAAP and may not be comparable with the calculation or similar measure for other companies. Funds from operations per share-diluted is calculated by dividing the funds from operations by the weighted average number of diluted shares outstanding.

The fiscal period for the Company is the 12 months ended March 31 of each year. The term 'fiscal 2006' is used throughout this report and refers to the period from April 1, 2005 through March 31, 2006.

(1) Netbacks are calculated by dividing the Company's total revenues and costs by the Company's total production volumes measured in boe.

(2) During the year ended March 31, 2006 the awarding of the D4 and Cauvery blocks in India increased the Company's net undeveloped land holdings by 2,558 and 957 square kilometres, respectively. During the year ended March 31, 2005 Niko relinquished 395 and 378 net square kilometres relating to the Surat Block and NEC-25, respectively, to the Government of India.

Subsequent to the year ended March 31, 2006 the Company added 172 square kilometres of net undeveloped land in Thailand.

(3) As of March 31, 2006 using NI 51-101 format and forecast prices.

(4) "Net" reserves are defined as those accruing to Niko's working-interest share after royalty interests owned by others are deducted, including a reduction to reflect any profit petroleum amounts that may be payable to the governments of India and Bangladesh.

(5) Present value discounted at 10 percent after income taxes using forecast prices and costs. Present value at March 31, 2005 before tax, using forecast prices and costs discounted at 10 percent, in thousands of dollars is $646,916 for proved reserves and $1,069,443 for proved plus probable reserves ($494,800 and $847,460 as at March 31, 2005).

PRESIDENT'S REPORT *to* SHAREHOLDERS

CORPORATE PROFILE

Niko is an international oil and natural gas exploration and production company with properties in India, Bangladesh and Thailand. High impact natural gas plays have been, and remain, the key component in Niko's strategy. The Company is continually evolving and has added several oil prospects to its portfolio. Fuelled by the success of its key natural gas properties, Niko is determined to continue its role as a leader in the field of international oil and natural gas exploration and production. Niko trades on the Toronto Stock Exchange under the symbol "NKO" and forms part of the S&P TSX Composite Index.

The past year has seen Niko commence a transition from solely a natural gas exploration and production company to one whose future contains both natural gas and oil exploration and production. The deep water D6 Block in India continued to prove its worth as a cornerstone of Niko's value. The D6 Block was the main contributor in a nearly 200 percent increase in Niko's working interest proved plus probable plus possible reserves and contingent resources and prospective resources from 1,165 billion cubic feet in the prior year to 3,417 billion cubic feet as at March 31, 2006. While Niko is pleased with the significant additions to the natural gas reserves in the D6 Block, the discovery of oil and gas in the Cretaceous interval unlocks the potential for a world-class oil province to emerge. The addition of oil to the Niko portfolio is not limited to the D6 Block, as Niko is targeting the oil producing potential in the Cauvery Block in India and the newly acquired Fang Block in Thailand. Another exciting prospect is the potential for additional large natural gas discoveries in the newly acquired deep water D4 Block off the east coast of India. The D4 Block has similar depositional environment and play types as the NEC-25 and D6 Block natural gas discoveries.

Edward S. Sampson
Chairman of the Board, President and Chief Executive Officer

In the D6 Block in India, a total of 18 consecutive discoveries have been made. This success has resulted in an increase to the independently assessed high estimate of gross original gas-in-place of 197 percent to 35.4 trillion cubic feet, of which Niko's working interest share is 3.5 trillion cubic feet not including the results of the recent P1-A and MA-1 discoveries. It was the drilling of the MA-1 well that resulted in the discovery of oil and natural gas in the Cretaceous interval. Throughout the course of the upcoming fiscal year, three rigs will be utilized to drill exploratory and development wells in D6, evaluate the several geological structures analogous to the MA-1 structure and drill in the deeper water portions of the block to evaluate the Miocene section, which has potential for both oil and natural gas, in the Pliocene natural gas zones.

For the NEC-25 Block, processing of a 3D seismic program acquired in fiscal 2006 is currently underway. With total estimates in excess of 8 trillion cubic feet of gross original natural gas-in-place based on the six wells drilled on the original 1,800 square kilometre 3D seismic prepared by Gaffney Cline & Associates (GCA), Niko is looking forward to the upcoming eight well drilling program. The drilling program may commence as early as the third quarter of fiscal 2007 with the first two wells designed to increase reserves in the commercially approved development area and three wells designated for the new 3D seismic area. The remaining three wells are dependant on the results of the first five.

Both the Hazira and Surat fields continue to provide a solid source of cash flow, contributing a combined total of $69.6 million to funds from operations. Production from the NSA-8 well in Surat commenced in the fiscal year and a total of four natural gas wells were placed on production in Hazira. In addition, Niko successfully drilled three oil wells from the Hazira offshore platform which were placed on production near the end of the fiscal year and are currently producing approximately 1,200 (400 net) barrels of oil per day.

In Feni, Niko successfully installed a compressor which could be put into operation in fiscal 2007. Drilling locations for two additional wells, Feni-6 and Feni-7 have been selected. Future capital activity at Feni has been postponed pending signing a Gas Purchase and Sales Agreement (GPSA) with the Government of Bangladesh and obtaining Government approval to drill.

Overall, average daily natural gas production increased by 31 percent to 80 million cubic feet per day from the Hazira, Surat and Feni properties. This increase in production underpinned an increase in revenues to $121.2 million. Additionally, these properties are consistently providing strong operating netbacks as operating costs fell by 15 percent in fiscal 2006 to $1.91 per boe.

Due to the increasing strength of the Canadian dollar, year-over-year operating netbacks fell to $16.86 per boe from $19.61 per boe.

While drilling the relief well at Chattak in June 2005, Niko encountered a second uncontrolled release of natural gas. The blowout was successfully killed by October 2005 and the drilling locations have been completely restored. A natural gas processing facility and pipeline have been completed and are ready for use. Niko will resume drilling upon receiving Government approval and signing the GPSA for the Feni field.

Niko has been active in Block 9 where 620 square kilometres of 3D seismic were acquired, production from the Bangora-1 well commenced and the Bangora-2 well was spudded and has recently reached target depth. Current production from the Bangora-1 well is approximately 50 Mcf per day (33 Mcf per day net). Niko will begin collecting revenue from the government when commerciality is declared, which is expected to be in September 2006. Electric log evaluation of the Bangora-2 well is currently underway. Indications from logging while drilling are encouraging with initial evaluation suggesting that some natural gas zones encountered in Bangora-2 well are thicker than those in the Bangora-1 well.

OUTLOOK

I believe Niko's future in Southeast Asia is more promising than ever. While we have encountered difficulties in Bangladesh, the fundamentals that took us there remain unchanged. The foundation of our presence in Bangladesh is based on that country's natural gas shortage and its potentially large natural gas reserves. Our aim is to marry those two uniquely opposite conditions, thereby resolving the situation. With perseverance and commitment, I am confident that we can reach that goal.

Niko has abundant drilling and seismic prospects to pursue in fiscal 2007. Our entry into a third Southeast Asian country, Thailand, is expected to provide additional growth in oil production with drilling to commence in the second fiscal quarter. We plan to drill each of our three Bangladesh properties. However, the drilling in Feni and Chattak is contingent upon signing a GPSA with the Government of Bangladesh and obtaining Government approval. We also have planned wells for both of our original deep-water blocks in India – NEC-25 and D6, which have experienced a drilling success rate of 100 percent thus far. The 2D seismic of our new deep-water block in India, D4, is currently being processed. In the recently acquired Cauvery Block in India, acquisition of a 3D seismic program is scheduled to commence in the second quarter of fiscal 2007 with drilling scheduled to commence late in the fiscal year.

With these numerous exciting ventures, Niko is ripe with opportunity for continued success in Southeast Asia.

ACKNOWLEDGEMENTS

As in the past, Niko's success in fiscal 2006 is owed to the hard work and contributions made by our dedicated management team and employees and the commitment of our valued shareholders. On behalf of the Board of Directors, I am pleased to express our sincere gratitude to all those involved in Niko's accomplishments.

Edward S. Sampson
Chairman of the Board, President and Chief Executive Officer
June 26, 2006

MANAGEMENT'S DISCUSSION *and* ANALYSIS

Management's Discussion and Analysis (MD&A) of the financial condition, results of operations and cash flows should be read in conjunction with the audited consolidated financial statements and accompanying notes. This MD&A is effective June 26, 2006. Additional information relating to the Company, including the Company's Annual Information Form (AIF), is on SEDAR at www.sedar.com.

The Company's activities are focused on the Asian subcontinent. Over the reporting period, revenue and expenses were generated and capital expenditures were made in India, Bangladesh and Canada, and capital expenditures were made in Thailand. The Company's activities are carried out primarily in U.S. dollars as well as the currencies of each country in which the Company operates. The Company reports financial results in Canadian dollars.

The selected financial information presented throughout the MD&A is prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP), except for funds from operations, funds from operations per share, operating netback, cash flow netback and earnings netback which are used by the Company to analyze the results of operations and liquidity. By examining funds from operations, the Company is able to determine its ability to fund future capital projects and investments. Funds from operations is calculated as cash flows from operating activities prior to the change in operating non-cash working capital. Funds from operations is not an alternative to cash flow from operating activities as determined in accordance with Canadian GAAP and may not be comparable with the calculation or similar measures for other companies. The consolidated statements of cash flows in the audited financial statements present the reconciliation between net income and cash flow from operating activities. Funds from operations per share-diluted is calculated by dividing the funds from operations by the weighted average number of diluted shares outstanding. Operating netback is calculated as the average sales price per boe, less royalties, profit petroleum and operating costs per boe and represents the cash margin directly related to production for every boe sold. Cash flow netback is calculated as the operating netback less other cash expenses per boe, including general and administrative expenses, interest and financing, other income and other expenses and represents the cash margin for every boe sold. Earnings netback is calculated as the cash flow netback less foreign exchange per boe and non-cash expenses per boe, including depletion and depreciation, future income taxes and stock-based compensation expense and represents net income for every boe sold. There are no comparable GAAP measures for operating netback, cash flow netback and earnings netback and these measures may not be comparable with the calculation or similar measures in other companies.

The fiscal period for the Company is the 12-month period ended March 31 of each year. The term 'fiscal 2006' is used throughout the MD&A and refers to the period from April 1, 2005 through March 31, 2006.

Barrel of oil equivalent (boe) is a measure used throughout the MD&A. Boe is derived by converting natural gas to oil in the ratio of 6 Mcf:1 bbl. Boe may be misleading, particularly if used in isolation. A boe conversion of 6 Mcf :1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

The information contained in this MD&A may contain forward-looking information. Forward-looking information is subject to numerous known and unknown risks and uncertainties including, but not limited to, results of operations, financial condition, capital spending, financing sources, commodity prices and the magnitude of oil and natural gas reserves. These risks and uncertainties may cause actual events and circumstance to differ materially from those predicted. Readers are cautioned not to place undue reliance on this forward-looking information.

Less than two percent of total corporate volumes and revenues are from oil and condensate production. Therefore, the results from oil and condensate production, which include all of the Canadian results, are not discussed separately.

OVERALL PERFORMANCE

The Company enjoyed the added benefit of a total of five more producing wells in India as well as a full year of production in Bangladesh. However, several factors offset this benefit and net income was reduced in comparison to the prior year. As the Company receives its revenues in U.S. dollars, the strengthening Canadian dollar over the past two years has partially offset the increase in revenue from increased production. Also, the Company experienced a decrease in Bangladesh sales as production was shut-in during the fourth quarter and an adjustment was made to the Bangladesh natural gas sales price. The Company's depletion expense increased due to higher production and a decrease in the reserve estimates of its producing properties. In fiscal 2005, the Company recorded a large income tax recovery which also increased the previous year's net income. These are the primary factors for the decrease in net income from the prior year.

The Company's funds from operations also fell in comparison to the prior year. The decrease was the result of the same factors that impacted net income with the exception of depletion as this is a non-cash item.

A total of $135.2 million was spent on capital additions which mainly consisted of development activities in the Hazira field in India, exploratory work in the D6 Block in India, development costs in Block 9 and costs incurred relating to data and relief well efforts at the Chattak field in Bangladesh. The resulting highlights of this capital spending were significantly increased natural gas reserves as well as a discovery in the Cretaceous interval in the D6 Block.

During fiscal 2006, the Company added two new exploration blocks in India – Cauvery and D4, and entered Thailand with the acquisition of an equity stake in the Fang Block, a production and exploration block. The Company continues to develop and explore its non-producing properties and a significant portion of its capital resources will be dedicated to this goal in the 2007 fiscal year.

SELECTED ANNUAL INFORMATION

Year ended March 31 (thousands of dollars, except per share amounts)	**2006**	2005	2004
Petroleum and natural gas sales	**121,168**	107,850	85,834
Net earnings	**(4,352)**	74,222	25,351
Per share basic ($)	**(0.11)**	2.08	0.76
Per share fully diluted ($)	**(0.11)**	2.03	0.74
Total assets	**517,258**	480,714	278,939
Total long-term financial liabilities	**6,779**	19,062	42,772
Dividends per share	**0.12**	0.12	0.12

Fiscal 2004 – 2005 Comparison

Petroleum and natural gas sales increased from fiscal 2004 to 2005 due to the commencement of production from the Hazira offshore platform in India, the Feni field in Bangladesh and recommencement of production from the Surat shallow natural gas field in India, partially offset by the decrease in the value of the U.S. dollar, as revenues are received in U.S. dollars. The increase in net income was 193 percent compared to the 26 percent increase in petroleum and natural gas sales. In addition to the increase in revenues, net income for the year was positively impacted by insurance proceeds received as well as reduced current income taxes, a recovery of prior years' income taxes and a future income tax reduction, all due to the recognition of the tax holiday in India. Earnings per share increased by 174 percent due to the increased production and the recognition of the tax holiday.

The February 2005 equity financing resulted in a significant cash balance at the end of fiscal 2005. Capital spending in India in fiscal 2005 totalled $57.6 million related to development activities in Hazira, drilling on the offshore platform and exploratory activity in the NEC-25 and D6 blocks. Capital spending in Bangladesh in fiscal 2005 totalled $60.7 million related to development activities in Feni, Chattak and Block 9. Accounts receivable increased due to increased revenues, an insurance receivable related to the blowout at Chattak-2, and the long-term income tax receivable increased due to the recovery of the prior years' income taxes.

Fiscal 2005 – 2006 Comparison

The increase in petroleum and natural gas sales from fiscal 2005 to fiscal 2006 was due to four more natural gas wells being placed on production at the Hazira offshore platform, the addition of the NSA-8 well at Surat, and an entire year of production at the Feni field in Bangladesh. The benefit of these production increases was partially offset by a decrease in the value of the U.S. dollar relative to the Canadian dollar as the Company receives its revenues in U.S. dollars and to decreased revenues in Bangladesh in the fourth quarter of fiscal 2006 due to a production shut-in and revenue adjustment.

The primary reasons for the decrease in net earnings and net earnings per share were an increase in depletion and depreciation expense due to a downward revision of producing reserves and a large income tax recovery recorded in fiscal 2005 due to the initial recognition of a tax holiday in India. An increase in stock-based compensation expense due to additional stock option grants also contributed to the decrease in net income. Total assets increased due to capital additions and increased accounts receivable, which were partially offset by the use of cash in funding the capital expenditures. The capital additions mainly consisted of development activities in the Hazira field in India, exploratory work in the D6 Block in India, development costs in Block 9 and costs incurred relating to data and relief well efforts at the Chattak field in Bangladesh.

The increase in accounts receivable was due to the non-payment of natural gas revenue by the Government of Bangladesh and an increase in insurance receivable related to the uncontrolled releases of natural gas in Chattak.

RESULTS OF OPERATIONS

REVENUE AND OPERATING INCOME

Year ended March 31, 2006 (thousands of dollars, except daily production)	India	Bangladesh	Canada	Total
Revenue	100,533	19,689	946	121,168
Pipeline revenue	983	–	–	983
Royalty	(17,345)	–	(98)	(17,443)
Profit petroleum	(7,890)	(3,938)	–	(11,828)
Operating and pipeline expenses	(7,214)	(2,395)	(147)	(9,756)
Net operating income [1]	69,067	13,356	701	83,124
Daily production (boe/day)	9,133	4,234	45	13,412

[1] Net operating income is a non-GAAP measure calculated as above.

Year ended March 31, 2005 (thousands of dollars, except daily production)	India	Bangladesh	Canada	Total
Revenue	96,500	10,929	421	107,850
Pipeline revenue	982	–	–	982
Royalty	(16,496)	–	(57)	(16,553)
Profit petroleum	(6,868)	(2,182)	–	(9,050)
Operating and pipeline expenses	(7,291)	(1,463)	(149)	(8,903)
Net operating income [1]	66,827	7,284	215	74,326
Daily production (boe/day)	8,445	1,834	24	10,303

[1] Net operating income is a non-GAAP measure calculated as above.

NETBACKS

The following table outlines the Company's operating and earnings netbacks for fiscal years 2006 and 2005.

	2006		2005	
	Natural Gas Total ($/Mcf)	(6:1) Total ($/boe)	Natural Gas Total ($/Mcf)	(6:1) Total ($/boe)
Price	4.09	24.75	4.76	28.68
Royalties	(0.59)	(3.56)	(0.74)	(4.40)
Profit petroleum	(0.40)	(2.42)	(0.40)	(2.41)
Operating costs	(0.31)	(1.91)	(0.36)	(2.26)
Operating netback	2.79	16.86	3.26	19.61
Pipeline and other income		0.84		0.58
Pipeline expense		(0.08)		(0.10)
General and administrative		(1.11)		(0.96)
Write-down of A/R		(0.33)		
Interest and financing		(0.75)		(0.43)
Insurance proceeds		-		0.89
Current taxes		(1.76)		3.66
Cash flow netback		13.67		23.25
Foreign exchange		(0.01)		0.49
Depletion and depreciation		(13.46)		(9.56)
Future income taxes		-		5.91
Stock-based compensation		(1.09)		(0.34)
Earnings netback		(0.89)		19.75

Netbacks are calculated by dividing the revenues and costs related to natural gas production in India and Bangladesh and revenues and costs in total for the Company by the volume of natural gas production in India and Bangladesh, measured in Mcf, and by the total production of the Company, measured in boe.

The following tables outline the Company's operating netbacks by country for fiscal years 2006 and 2005.

Year ended March 31, 2006	Joint Venture [1]	Surat	India	Bangladesh	Canada
Average daily production					
Oil (bbls/day)	13	-	13	25	45
Natural gas (mmcf/day)	45	10	55	25	-
Total combined (boe/day)	7,472	1,661	9,133	4,234	45
Revenues, royalties and operating costs					
Gross revenue received ($/boe)	30.57	28.30	30.16	12.74	55.50
Royalties ($/boe)	(5.18)	(5.33)	(5.20)	-	(5.86)
Profit petroleum ($/boe)	(2.89)	-	(2.37)	(2.55)	-
Operating costs ($/boe)	(1.70)	(3.57)	(2.05)	(1.55)	(8.83)
Operating netback ($/boe)	20.80	19.40	20.54	8.64	40.81

[1] The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati.

Year ended March 31, 2005	Joint Venture [1]	Surat	India	Bangladesh	Canada
Average daily production					
Oil (bbls/day)	20	–	20	13	24
Natural gas (mmcf/day)	43	8	51	10	–
Total combined (boe/day)	7,163	1,282	8,445	1,834	24
Revenues, royalties and operating costs					
Gross revenue received ($/boe)	31.52	30.14	31.31	16.33	46.96
Royalties ($/boe)	(5.26)	(5.89)	(5.35)	–	(6.62)
Profit petroleum ($/boe)	(2.63)	–	(2.23)	(3.26)	–
Operating costs ($/boe)	(1.16)	(8.26)	(2.24)	(2.19)	(17.22)
Operating netback ($/boe)	22.47	15.99	21.49	10.88	23.12

[1] The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati.

Netbacks by country are calculated by dividing the revenues and costs related to combined oil and natural gas production by the volume measured in boe for that country.

INDIA

REVENUE, ROYALTIES AND PROFIT PETROLEUM

India represented approximately 83 percent of the Company's oil and natural gas revenue or $100.5 million in fiscal 2006 as compared to 90 percent of the Company's oil and natural gas revenue or $96.5 million in fiscal 2005. Average daily natural gas production in India increased by 8 percent during fiscal 2006 to 55 million cubic feet per day from 51 million cubic feet per day the previous fiscal year. This production increase was due to the addition of four wells on the offshore platform at Hazira and the drilling of the NSA-8 well at Surat. Over the next fiscal year, the Company expects a decrease in production due to natural declines.

The average plant outlet price received by the Company for its natural gas in India during fiscal 2005 decreased by 4 percent, due to the drop in the U.S. dollar versus the Canadian dollar, to $4.15 per Mcf from $4.31 per Mcf in fiscal 2005. Most of the prices in the Company's natural gas contracts expired in November 2004 and January 2005 and are currently being renegotiated. Though no formal contracts have been signed, the Company has agreed to a price of US$3.65 per Mcf with four customers. The Company has signed contracts with two customers at a price of US$3.75 per Mcf and is recording revenue relating to remaining customers at prices between US$3.45 per Mcf and US$3.65 per Mcf pending a price renegotiation. Under the terms of all natural gas contracts the purchaser is responsible for transportation charges, royalties and sales taxes. The latter two charges, levied against Niko by the Government, vary according to the type of purchaser and are collected on top of the contracted sales price. In fiscal 2006, Niko charged and remitted $17.3 million or 17.3 percent of Indian sales (2005 – $16.5 million, or 17.1 percent of Indian sales) in royalties and sales taxes, increasing the average purchaser's cost to $5.02 per Mcf in fiscal 2006 (2005 – $5.21).

Pursuant to the terms of the PSCs the Government of India is entitled to a sliding scale share in the profits once the Company has recovered its investment. The Government's share increases as the Company recovers a multiple of its investment. In fiscal 2006, the Government was entitled to 20 percent of the cash flow defined as revenue, net of royalties, less operating costs and capital expenditures, from the Hazira field. This amounted to $7.9 million in the year (2005 – $6.9 million). The increase in profit petroleum reflects the increased cash flows from the Hazira field. In fiscal 2007, the Government of India will again be entitled to 20 percent. The Company currently does not incur any profit petroleum expense with respect to the Surat field.

BANGLADESH

REVENUE AND PROFIT PETROLEUM

Production from the Feni field in Bangladesh commenced in November 2004. Revenue from the Feni field increased from $10.9 million in fiscal 2005 to $19.7 million in 2006. Production in fiscal 2006 of 25 million cubic feet per day was relatively consistent with production of 26 million cubic feet per day in the period from November 2004 to March 31, 2005 of the comparative year. The increase in revenue was mainly due to the Company experiencing a full year of production at Feni compared to the four-month period in fiscal 2005, which was partially offset by the Company recognizing revenue from Bangladesh at a lower price than in fiscal 2005 and production being shut-in during the fourth quarter of fiscal 2006. During fiscal 2005, the Company recorded revenue from the Feni field at a price of US$2.20 per Mcf (CAD$2.68 per Mcf). During the quarter ended December 31, 2005, the Company made an adjustment to record all revenue since inception at a price of US$2.10 per Mcf. This resulted in a decrease in Bangladesh revenue of CAD$1.0 million. For the year ended March 31, 2006, the Company further reduced the Bangladesh natural gas sales price since inception to US$1.75 per Mcf. This resulted in an average price for the year of CAD$2.09 and a further decrease in Bangladesh sales of CAD$3.4 million. During the fourth quarter of fiscal 2006, the Company shut-in the Feni field in Bangladesh in an effort to draw attention to the growing account receivable owed by the Government of Bangladesh as well as for scheduled maintenance. Due to the resulting decrease in production, revenue decreased by approximately CAD$3.0 million in the fourth quarter. Natural declines are beginning to take effect in Feni. Currently, the Company is forecasting average production from the Feni field of approximately 15 to 20 million cubic feet per day. However, with the anticipated drilling of Feni-6 and Feni-7, which is subject to the Company and the Government signing a Gas Purchase and Sales Agreement and the Company obtaining Government approval to drill, the Company expects production levels of approximately 35 million cubic feet per day.

Pursuant to the terms of the JVA, the Government of Bangladesh is entitled to a sliding scale share in the revenues. The Government's share increases as the Company recovers a multiple of its investment. During fiscal 2005 and fiscal 2006 the Government was entitled to 20 percent of the revenues from the Feni field. This amounted to $3.9 million in fiscal 2006 and $2.2 million in fiscal 2005; the increase is consistent with the higher revenues. The relief well costs are not eligible for inclusion in the profit petroleum calculation. The Company expects the Government's share to increase to 25 percent by mid-fiscal 2007 depending on the timing of capital expenditures.

The Company does not incur any royalty expense in Bangladesh.

OPERATING EXPENSES

Operating costs decreased by 15 percent to $1.91 per boe in the year ended March 31, 2006 from $2.26 per boe in fiscal 2005. Operating costs pertaining to India fell by 8 percent from $2.24 per boe to $2.05 per boe. The decrease is due to one-time start-up costs in Surat incurred in the comparative year that were not present in fiscal 2006. In Bangladesh, operating costs decreased by 29 percent from $2.19 per boe to $1.55 per boe. The decrease in Bangladesh operating costs is also due to one-time start-up costs incurred in the prior year. Operating costs in both countries were also lowered due to a reclassification of branch costs from operating to general and administrative expenses. The Company expects operating costs of $1.90 to $2.00 per boe for fiscal 2007.

PIPELINE REVENUE

In fiscal 2003 the Company resolved the dispute over the ownership of the 36-inch pipeline at Hazira, although legal title to the pipeline has not yet been transferred to the joint venture. Pipeline revenue for fiscal 2006 was consistent with fiscal 2005 at $1.0 million as the same number of vendors utilized the pipeline.

INDIA

The Company has a 33.33 percent working interest in the offshore platform at Hazira. The drilling of three oil wells from the offshore platform – OS-7, OS-8 and OS-9, was completed during the year. Production from these wells began at the end of March 2006. The Company also intends to drill one to three oil wells from the land-based drilling platform. Capital expenditures in the 2006 fiscal year were $22.4 million (net) related to drilling and completion activities on the offshore platform of natural gas wells OS-5, OS-6 and OS-10 and oil wells OS-7, OS-8 and OS-9 and the related oil facility construction. Capital expenditures for fiscal 2007 are forecast at $3.5 million to $4 million (net) primarily related to drilling additional wells from the land based drilling platform.

The Company has a 10 percent working interest in the D6 Block off the east coast of India. The Company participated in the drilling of five wells during fiscal 2006. New oil and natural gas discoveries from three exploration wells were made during fiscal 2006 in the E-1, P-1A and MA-1 wells. The MA-1 well was the first test of the Cretaceous section in D6 and resulted in the discovery of both oil and natural gas in that interval. The P-1A well was also significant for its discovery of natural gas in the Miocene section (along with natural gas in the Pliocene section). In addition, two development wells were drilled, A-10 and B-7, to secure further reservoir and reserve information for the Dhirubhai natural gas development. As a result of the information gathered, reserves and productivity of the natural gas zones have both increased and the field development plan has been altered to handle increased production rates.

During fiscal 2006, a 3,474 square-kilometre 3D seismic program was acquired that increased the 3D seismic coverage to most of the remaining areas of the block. Processing is scheduled to be completed in August 2006 with interpretation and justifiable well selection to follow immediately.

Fiscal 2007 will be the most active to date in the D6 Block with three rigs drilling to develop and evaluate the oil and natural gas potential of the block. Exploration drilling will continue in D6 with an initial focus on the evaluation of the Cretaceous oil potential. Subsequently, evaluation of the deeper-water Pliocene natural gas and Miocene natural gas, and possibly oil, is expected to commence in earnest. Development drilling of the Dhirubhai field will be underway and continue into fiscal 2008. In addition, development drilling of the Cretaceous oil could commence once commerciality is established and development plans have been approved.

Capital expenditures in fiscal 2006 were $19.8 million (net) for drilling activities related to the P-1A, A-10A, B-7 and MA-1 wells and seismic acquisition over the remaining deep water area of the block. The Company expects to incur capital expenditures in fiscal 2007 of $45 million to $50 million, the majority of which is expected to be spent on drilling and production facility costs with some seismic costs.

The Company has a 10 percent working interest in the NEC-25 Block in the Mahanadi basin off the east coast of India. In fiscal 2006 a 1,700 square-kilometre 3D seismic program was acquired immediately south of the previous 3D program. Processing is underway and expected to be completed by August 2006, followed by interpretation and well selection. Exploration drilling is scheduled to commence as early as the third quarter of fiscal 2007 with the first two wells designed to increase reserves in the commercially-approved development area. In total, an eight-well program is planned with three wells designated for the new 3D seismic area. During fiscal 2006, the Company spent $1.3 million (net) on 3D seismic. The forecasted expenditures for fiscal 2007 are $10 to $12 million (net) primarily related to exploration drilling.

The Company holds a 100 percent working interest in the Cauvery block located in the Cauvery basin on the southeastern coast of India. The Company has applied to the state government of Tamil Nadu for a Petroleum Exploration License (PEL); it is expected the PEL will be signed early in the second quarter of fiscal 2007. A 550 square-kilometre 3D seismic program is scheduled to commence in the second quarter of fiscal 2007 subsequent to signing of the PEL. Following the evaluation of the 3D seismic, a five-well drilling program is planned to commence in late fiscal 2007. The minimum capital expenditures of this work under the Phase I Commitment, are US$15.9 million. The Company expects to spend $15 to $17 million, the majority of which is expected to be seismic costs with some drilling costs in the upcoming fiscal year.

In the deep-water block MN-DWN-2003/1 (D4), located in the Mahanadi basin, in which Niko holds a 15 percent interest, 2,366 kilometres of 2D seismic were acquired in early fiscal 2007. Processing of the 2D seismic is expected to be completed in October 2006 with interpretation to follow. The 2D seismic is the first step of the Phase I exploration, which also includes 1,800 square kilometres of 3D seismic and drilling of three exploratory wells. Acquisition of this seismic program is scheduled to begin in late fiscal 2007. The estimated cost of the Phase I commitment is US$97.6 million (US$14.6 million net). The Company's forecasted capital expenditures for the D4 Block for fiscal 2007 are $2 to $3 million related to seismic activities.

BANGLADESH

At Feni, the Company plans to drill two new wells to extend the structure north and south. Construction of drilling locations for Feni-6 and Feni-7 has been completed. Future drilling at Feni has been postponed subject to the Company and Government signing a GPSA and obtaining Government approval to drill. Capital expenditures in the year were $5.5 million related to development activities and site preparation for the two planned wells as well as the purchase and installation of the compressor.

The Chattak structure covers a surface area of 376 square kilometres. The upper fault block to the west previously produced from one well, while the down-thrown fault eastern block has not been drilled. Three drilling locations have been identified on the western part of the Chattak structure and one location on east Chattak. Drilling of the first planned well and relief well resulted in an uncontrolled release of natural gas in January and June 2005, respectively. Drilling of a data acquisition well, Chattak-2C, was completed in September 2005. This well was followed by drilling of a relief well, Chattak-2B, which intersected the original Chattak-2 well in the reservoir section of the blowout sand and was cemented on October 9, 2005. Since this successful kill of the blowout, the natural gas seeping to surface has completely ceased and the drilling locations have been successfully restored. The drilling of the second scheduled well, Chattak-3, could commence in fiscal 2007 followed by the drilling of Chattak-4. During the year, the Company finished construction of a natural gas processing facility at Chattak field capable of handling up to 50 million cubic feet of natural gas per day. A 16-inch diameter, 16-kilometre pipeline from Chattak to the tie-in point with Jalalabad Gas Transmission and Distribution Ltd. was completed, pressure tested, and is ready for use. In addition, the drilling location for the East Chattak well was completed. During the year, $63.7 million was capitalized relating to the drilling of the data and relief wells, the natural gas plant and the pipeline at Chattak. Included in the $63.7 million of capital spending is US$38.8 million which is the excess of total capital spending related to the relief well of US$78.8 million over the amount expected to be reimbursed by insurance, US$40.0 million. Further spending at Chattak has been postponed pending signing a GPSA for the Feni field with the Government of Bangladesh and obtaining Government approval for the wells.

An additional $3.0 million was spent on the Feni and Chattak properties for inventory and other allocated common costs.

The Company has a 60 percent working interest in Block 9 and is also responsible for the costs associated with a 6.67 percent earned interest in the Block held by BAPEX. Two of the three exploration wells drilled to date encountered commercial quantities of natural gas. The Bangora-1 well tested natural gas at rates higher than 120 million cubic feet per day from three zones. The 620 square-kilometre 3D seismic program over the Lalmai/Bangora anticline is complete. In the first quarter of fiscal 2007, as the natural gas facilities were being completed, long-term test production of the Bangora-1 well commenced and the Bangora-2 well was spudded. The first of a possible four appraisal wells, Bangora-2 is being directionally drilled from the Bangora-1 site to test for reservoir extension of the highly productive sands encountered in the Bangora-1 well. Drilling from the Bangora-1 site will allow for this well to be pipeline-connected for immediate production once it has been successfully completed. Capital expenditures in fiscal 2006 were $17.4 million (net) for the tie-in of Bangora-1, the drilling of Bangora-2, seismic, engineering and general and administrative charges. Capital expenditures for fiscal 2007 are forecast at $30 to $35 million (net) and are largely made up of Bangora-2 and future well drilling costs.

The Bangora-1 well is currently producing at a rate of more than 50 million cubic feet per day (33 million cubic feet per day net). According to the terms of the Block 9 PSC, the Company and its joint-venture partner are to be paid once commerciality is declared. The Company expects commerciality to be declared in September 2006 at which time the Company expects to receive the revenue owed for all natural gas produced in Block 9 to date.

THAILAND

Niko resources entered Thailand through the acquisition of a 50 percent equity stake in a production and exploration block in northern Thailand. The development portion is over the Mae Soon field in the Central Fang basin while the exploration areas are immediately south (176 square kilometres) and north (165 square kilometres) of the producing central Fang basin. The Company has a commitment for 12 workovers in the Mae Soon field with workover operations expected to commence in August 2006. The Company has minimum capital commitments of US$10.4 million in connection with the development drilling and workover plan which must be spent over the next five years. On the exploration areas of the block, the Company has commenced a 150 square-kilometre 3D seismic program which is expected to be completed in August 2006, with the drilling of the first of 10 wells expected to commence in December 2006. The minimum capital commitments for the exploration portion of the block are US$5.9 million which must be spent over the next two years. Throughout fiscal 2007, the Company expects to spend $5 to $7 million in connection with planned workovers in the Mae Soon field and $12 to $15 million related to seismic and drilling activities on the exploration area of the Fang Block.

CORPORATE

INTEREST INCOME

Interest income of $2.7 million (2005 – $1.2 million) was earned on excess cash balances during the year. The increase is due to higher cash balances remaining from the equity issuance in February 2005 and the additional US$20 million drawn on the debt facility.

INTEREST AND FINANCING

The Company incurred interest and financing expenses of $3.7 million in fiscal 2006 compared to $1.6 million in the prior fiscal year. The increase is a result of the Company drawing down the remaining US$20.0 million of the debt facility in fiscal 2006, thereby significantly increasing the average total debt outstanding.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses were $5.4 million or $1.11 per boe for fiscal 2006 compared to $3.6 million or $0.96 per boe in the prior year. The increase is due to increased professional fees, including legal, audit and tax fees, resulting from more complex business transactions; lower overhead recoveries resulting from reduced capital spending; and reclassification of branch office costs from operating costs, partially offset by the capitalization of general and administrative expenses.

WRITE-DOWN OF ACCOUNTS RECEIVABLE

During the year ended March 31, 2005, the Company recorded production from the Feni field in Bangladesh at a price of US$2.20 per Mcf. In the 2006 fiscal year, it became apparent to the Company that a price of US$2.20 per Mcf was no longer attainable for production from the Feni field. Accordingly, in the last quarter of fiscal 2006, the Company adjusted revenue since inception to a price of US$1.75 per Mcf. The write-down of accounts receivable of $1.6 million is the result of the write-down of the fiscal 2005 Bangladesh receivable to a rate of US$1.75 per Mcf.

The adjustment to fiscal 2006 revenue was recorded by adjusting revenue, royalties, taxes and accounts receivable in the current year.

FOREIGN EXCHANGE

The Company's long-term debt is denominated in U.S. dollars. Due to the strengthening of the Canadian dollar in the year, the Company incurred an unrealized foreign exchange gain on the outstanding debt. The Company incurs an unrealized foreign exchange gain or loss on long-term accounts payable and accounts receivable and restricted cash.

The Company repatriates its revenues out of India in U.S. dollars. A portion of the funds is kept in U.S. dollars as the majority of planned capital expenditures are in that currency. As a result, there is a foreign exchange effect due to the change in the Canadian dollar versus the U.S. dollar.

In fiscal 2006, the Company incurred a foreign exchange loss of $0.04 million compared to a gain of $1.9 million in the same period in the previous year. The foreign exchange loss incurred for fiscal 2006 is the result of the combined effect of the loss on the conversion of U.S. dollars held in cash and the loss on U.S. dollar receivables in excess of payables exceeding the gain on U.S. dollar-denominated long-term debt. In the prior year, the Company's U.S. dollar-denominated debt exceeded the average balance of U.S. dollars held in cash and U.S. dollar receivables, resulting in a foreign exchange gain.

INSURANCE PROCEEDS

The life insurance proceeds recorded in fiscal 2005 related to a key-man term life insurance policy held by the Company on the life of Robert N. Ohlson, the former President, who died suddenly on November 24, 2004 from natural causes.

STOCK-BASED COMPENSATION EXPENSE

The Company's stock-based compensation expense increased from $1.3 million in fiscal 2005 to $5.3 million in fiscal 2006. The increase is due to stock options granted in the fourth quarter of fiscal 2006.

DEPLETION AND DEPRECIATION

Fiscal 2006 depletion in India was $51.9 million or $15.57 per boe of production compared to $29.7 million or $9.64 per boe in 2005. Increased production resulted in higher depletion and this impact was compounded by a downward revision in reserves for the years ended March 31, 2005 and 2006. The fiscal 2005 reserves decreased by 39 billion cubic feet due to a technical revision at Hazira, while the fiscal 2006 reserves decreased due to downward revisions resulting from continued reservoir performance information at the Hazira and Surat fields.

Depletion in Bangladesh was $12.1 million or $7.84 per boe of production in fiscal 2006 compared to $5.8 million or $8.72 per boe in the previous year. The increased depletion expense is due to a full year of production as compared to the period from November 2004 to March 31, 2005, partially offset by a lower rate of depletion expense per boe. The lower depletion expense per boe is due to the Company using a larger reserve base for the depletion calculation for the quarters ended September 30, 2005 and December 31, 2005 because of an expected increase in reserves due to the installation of a compressor. The expected increase in reserves never materialized, as the compressor was not placed into operation at March 31, 2006. In the fourth quarter of fiscal 2006, the Company added a portion of Block 9 to the depletable base as it was ready for production. The impact of this on the depletion calculation was minimal.

Depreciation expense was $57,000 in both fiscal 2005 and 2006. Accretion expense was $351,000 in fiscal 2006 compared to $223,000 in fiscal 2005. The asset retirement obligation was $6.8 million in fiscal 2006, versus $4.6 million in fiscal 2005. The increase is due to the addition of wells at Hazira, Surat, D6 and Chattak. Starting in fiscal 2007, the Company expects to contribute funds to a restricted bank account for restoration under the Government of India's Site Restoration Fund, which requires companies to cover future restoration costs through a contribution of a portion of their profits over time.

INCOME TAXES

The Company's overall tax provision for fiscal 2006 was a charge of $8.6 million compared to a credit of $36.0 million in the previous fiscal year. The Company pays income tax at the highest rate of the jurisdictions in which it operates. The Company's current tax provision for the year increased to $8.6 million compared to a credit of $13.8 million in the previous year. In the previous year, the Company recognized the benefit from the preservation of the India tax holiday through a tax sparing provision of the Canada-India Tax Convention. This resulted in a recovery of prior year taxes. Taxes in the current year were recognized at a rate of 41.82 percent of taxable income in India and 4.0 percent of revenues after profit petroleum in Bangladesh. The result is an increase in taxes year-over-year. The current tax provision includes Indian tax of $7.9 million and Bangladesh tax of $0.7 million (credit of $14.1 million and charge of $0.3 million in the

previous year, respectively). There is no future tax provision in the year due to the continued recognition of a tax holiday in India. In the prior year, there was a future income tax recovery of $22.2 million due to the recognition of the benefit from the preservation of the India tax holiday through a tax sparing provision of the Canada-India Tax Convention.

As a result of the tax holiday in India, the Company pays the greater of 41.82 percent of net income in India after a deduction for the tax holiday and minimum alternative tax. The minimum alternative tax rate has increased to 10.455 percent from 7.84 percent in the prior year.

In the current year, production from the land-based drilling platform was lower than previously expected and the offshore platform has not yet recovered its costs, therefore is still using regular tax deductions, resulting in a lower deduction for the tax holiday. The Company recorded current income taxes at a rate of 41.82 percent of net income after a deduction related to the tax holiday, resulting in an effective current tax rate in India of 27 percent for the year. In the prior year, the effective tax rate was 14 percent. There were significant tax deductions in the prior year when the offshore platform came online. The decreased capital spending and no deduction for the tax holiday on the offshore platform is the cause of the increased effective tax rate.

The Company paid tax in Bangladesh at a rate of 3.75 percent of revenues net of profit petroleum until June 30, 2005. Since July 1, 2005 the Company had paid tax at a rate of 4.0 percent of revenues, net of profit petroleum. This amounted to $0.7 million in the year compared to $0.3 million in the prior year. The increase is due to higher production resulting in increased sales.

CAPITAL EXPENDITURES

A total of $135.2 million was spent on capital additions in fiscal 2006 compared to $119.1 million in the previous year. In Hazira, a total of $22.4 million (net) related to drilling and completion activities on the offshore platform of the natural gas wells OS-5, OS-6 and OS-10 and the oil wells OS-7, OS-8, OS-9 and oil facility construction. In Surat, the net effect of a sale of inventory and various minor additions was a reduction in capital of $0.1 million. In the D6 Block, capital expenditures in fiscal 2006 were $19.8 million (net) for drilling activities related to the P-1A, A-10A, B-7 and MA-1 wells and seismic acquisition over the remaining deep water area of the block. During fiscal 2006, the Company spent $1.3 million (net) on 3D seismic in the NEC-25 Block.

In the Feni field in Bangladesh, capital expenditures in fiscal 2006 were $5.5 million related to development activities and site preparation for the two planned wells as well as the purchase and installation of a compressor. During the year, $63.7 million was capitalized relating to the drilling of the data and relief wells, the natural gas plant and the pipeline in Chattak. Included in the $63.7 million of capital expenditures is US$38.8 million which is the excess of total capital spending related to the relief well of US$78.8 million over the amount expected to be reimbursed by insurance, US$40.0 million. An additional $3.0 million was spent on the Feni and Chattak properties for inventory and other allocated common costs. In Block 9, capital expenditures in fiscal 2006 were $17.4 million (net) for the tie-in of Bangora-1, the drilling of Bangora-2, seismic, engineering and general and administrative charges.

A total of $3.4 million was also spent on various other capital activities, including acquisition and other pre-exploration and development costs in Cauvery, the D4 Block and Thailand.

The Company capitalized $0.9 million of general and administrative expenses and $0.7 million of stock-based compensation expense in fiscal 2006 (2005 – nil).

DIVIDEND

The Company declared four quarterly dividends during fiscal 2006 of $0.03 per share each, totalling $4.6 million (2005 – $4.4 million). While the Company intends to pursue a policy of paying quarterly dividends, the level of future dividends will be determined by the Board of Directors in light of income (loss) from operations, capital requirements and the financial condition of the Company. The Company is restricted under the terms of its credit facility to a maximum dividend of the greater of 15 percent of its net income from the most recently completed financial quarter and $0.03 per share on a quarterly basis.

At March 31, 2006 the Company had a working capital deficiency of $20.0 million, which included $39.2 million of cash and cash equivalents.

The current portion of long-term debt increased at fiscal year-end 2006 compared to March 31, 2005 due to a draw-down of the remaining US$20 million available of long-term debt and was offset by the scheduled repayments. At March 31, 2006 long-term debt was $28.5 million compared to $21.5 million at March 31, 2005. The difference is attributable to the additional US$20 million drawn on the facility, less the September and March payments of US$6.66 million and US$6.68 million, respectively, and a change for the foreign exchange gain. If the Company fails to meet certain covenants, the loan will become payable at the discretion of the creditor. One of the covenants is to maintain a minimum level of loan coverage ratios. As at March 31, 2006, the Company was not able to meet two of its five loan coverage ratios. As a result, according to the terms of the loan agreement, the loan became payable at the discretion of the creditor and the full amount of the loan has been classified as a current liability. However, the creditor is aware of the coverage ratio violations and has made no indication that the loan will be called and the Company is currently working with the creditor to amend the loan agreement to place the Company in compliance with its loan coverage ratios. In the upcoming fiscal year, the Company has two scheduled debt repayments on September 15, 2006 and March 15, 2007 in the amounts of US$6.68 million and US$5.92 million respectively.

The Company has planned capital expenditures of $135 to $140 million (net) for the 2007 fiscal year.

Based on the cash requirements described above, the Company does not expect its funds from operations will be sufficient to meet its working capital requirements, planned capital expenditures and scheduled debt repayments. As a result, the Company expects additional financing will be required during the upcoming fiscal year. The Company expects to meet obligations as they become due and remedy the working capital deficiency using funds from operations and the expected financing. Although successful in raising funds in the capital market in the past, the Company's ability to raise funds in the future is subject to market or commodity price changes, economic downturns and the future performance of the Company. Furthermore, the factors described below may impact the amount and timing of the expected financing.

The restricted cash on the balance sheet at March 31, 2006 of $15.6 million relates to the performance guarantee the Company provided to the Government of Bangladesh in the amount of US$13.3 million as specified in the production sharing agreement for Block 9. Subsequent to March 31, 2006, Export Development Canada provided a performance security guarantee on behalf of the Company to the Government of Bangladesh and the US$13.3 million was returned to the Company.

The long-term account receivable of CAD$17.4 million (US$14.9 million) is outstanding from one customer. Since the commencement of production in Bangladesh in November 2004, the Company has sold all of its natural gas and condensate production in Bangladesh to one customer, the Government of Bangladesh. The receivable is currently being recognized at a price of US$1.75 per Mcf based on negotiations with the Government; previously, the receivable had been recognized at prices of US$2.20 per Mcf and US$2.10 per Mcf. The Company has received two payments totalling US$4.0 million since the commencement of production.

At the end of March 2006, the Company had completed negotiating the terms for the Gas Purchase and Sales Agreement (GPSA) for the Feni field. The process of obtaining formal approval of the GPSA from the Government of Bangladesh is expected to proceed in the first half of fiscal 2007. The natural gas price negotiated is US$1.75 per Mcf.

Included in accounts receivable is $0.4 million recorded as revenue for the incremental price increases still under negotiation with some of the Hazira natural gas customers. The Company has 12 contracts for the sale of natural gas from the Hazira field. Most of the natural gas contracts are U.S. dollar-denominated and the price had been set at the Indian Rupee equivalent of US$3.45 per Mcf while spot sales were at US$3.75 per Mcf. The price provisions in most of the contracts have expired and most of the contracts contain a renewal provision to renegotiate based on mutual

agreement of market-related prices. Though no formal contracts have been signed, the Company has agreed to a price of US$3.65 per Mcf with four customers. The Company has signed contracts with two customers at a price of US$3.75 per Mcf and is recording revenue relating to remaining customers at prices between US$3.45 per Mcf and US$3.65 per Mcf pending a price renegotiation. The Company is confident the negotiated price will be consistent with the price currently being billed and the full amount owed from these customers will be collected.

Included in accounts receivable is US$14.2 million receivable from the insurers with respect to the uncontrolled release of natural gas which occurred while drilling the Chattak-2 well and the subsequent Chattak-2A relief well in January and June 2005, respectively. The Company had a control-of-well insurance policy with US$20.0 million of coverage for each of the wells. Costs totalling US$22.9 million have been submitted to the insurers related to the first blowout and US$19.7 million was received as at March 31, 2006. Costs to control the second blowout include drilling of the data acquisition well, Chattak-2C, and the relief well, Chattak-2B. These costs totalled US$55.8 million to the end of March 31, 2006 and have been submitted to the insurers; US$6.1 million was received as at March 31, 2006. The Company expects to collect both the remaining US$0.3 million outstanding under the first policy and the US$13.9 million outstanding under the second policy; however, no assurance can be given that all costs submitted up to the policy limits will be covered under the insurance policies. Subsequent to March 31, 2006, the Company received US$8.5 million under the second insurance policy and continue to work with the insurers to collect the remaining amount.

During the quarter ended September 30, 2005, the Company was named as a defendant in a lawsuit that has been filed in the state of Texas, by a number of plaintiffs who claim to have suffered damages as a result of the uncontrolled releases of natural gas that occurred at the Chattak-2 well in Bangladesh in January and June 2005. Damages being sought total in excess of US$250 million. A court date has been set for July 7, 2006 to hear the Company's arguments that the case should be dismissed due to lack of jurisdiction in the state of Texas. The Company believes that the outcome of the lawsuit and associated cost, if any, is not determinable. As such, no amounts have been recorded in the consolidated financial statements for the year ended March 31, 2006.

Also during the quarter ended September 30, 2005 a group of petitioners filed a writ with the Supreme Court of Bangladesh against, among others, Niko Resources (Bangladesh) Ltd., a subsidiary of the Company. The petitioners are requesting that the Government withhold future payments (US$14.9 million or CAD$17.4 million outstanding as at March 31, 2006) to the Company relating to the production from the Feni field and that all bank accounts of the Company maintained in Bangladesh be frozen. Currently, the Company is unable to repatriate funds from the country.

During the quarter ended December 31, 2005 Niko Resources (Bangladesh) Ltd. received a letter from the Government of Bangladesh demanding the following as compensation for the uncontrolled flow problems that occurred in the Chattak field in January and June 2005: 3 billion cubic feet of free natural gas be delivered from the Feni field as compensation for the burnt natural gas; 5.89 billion cubic feet of free natural gas be delivered from the Feni field as compensation for the sub-surface loss; Taka 845,583,973 (CAD$14.8 million) for environmental damages, which is subject to be increased upon further assessment; unconditional acceptance that an additional quantity of approximately 45 billion cubic feet of natural gas as compensation for further sub-surface loss is to be delivered free or an equivalent monetary value is to be provided to the Government of Bangladesh, until the actual quantity of natural gas is determined; a bank guarantee in the value of 45 billion cubic feet of natural gas to be provided, and any other claims that arise from time to time. The Company believes that the outcome of the Government's claims and the associated cost to the Company, if any, is not determinable. As such, no amounts have been recorded in these consolidated financial statements as at March 31, 2006.

The Company and its partner have capital commitments for Phase I development as per the PSC signed for the D4 Block of US$97.6 million (US$14.6 million net to the Company), which must be expended over the next four years. The PSC Phase I three-year commitment minimum capital expenditures for the Cauvery Block are US$15.9 million. In Thailand, the Company has a commitment for 12 workovers, with minimum capital commitments of US$10.4 million over the next five years for the Mai Soon field on the Fang Block. With regard to the exploration areas to the north and the south of the Mae Soon field, the Company has a US$5.9 million capital commitment to drill 10 wells over the next two years.

CONTRACTUAL OBLIGATIONS

(dollars)	Total	Payments Due by Period Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Current portion of long-term debt [1]	28,523,000	28,523,000	–	–	–
Guarantees [2]	15,563,000	15,563,000	–	–	–
Office leases	1,900,000	368,000	651,000	410,000	471,000
Total contractual obligations	45,986,000	44,454,000	651,000	410,000	471,000

(1) A project facility (the facility) was established to fund the Company's development activities on India's west coast, specifically the Hazira offshore platform project and the Surat development project. At March 31, 2005, the facility limit was US$30 million of which US$20 million was drawn. During the year ended March 31, 2006 the loan amount was expanded from US$30 million to US$40 million as certain financial and operational criteria were met at Hazira and the remaining US$20 million was drawn. On September 15, 2005 the Company made a repayment for 11.1 percent (US$2.22 million) of the second US$20 million drawn plus 11.1 percent (US$4.44 million) of the total amount drawn of US$40 million. On March 15, 2006 the Company made a repayment for 16.7 percent (US$6.68 million) of the total amount drawn. As at March 31, 2006 US$24.4 million was outstanding. There will be four more semi-annual repayments on March 15 and September 15 of each year; the next installment will be for 16.7 percent (US$6.68 million) of the total amount drawn (US$40 million) and the remaining three installments for 14.8 percent (US$5.92 million) of the total amount drawn (US$40 million). Interest is payable semi-annually on March 15 and September 15 and accrues at the London Inter Bank Offered Rate (LIBOR) plus 4.5 percent from the date of drawdown (LIBOR plus 3 percent once security is perfected).

The security will be perfected once the Management Committee of the Hazira property, which is comprised of members of the Company and its joint-venture partner as well as the Indian Government, gives its formal approval.

If the Company fails to meet certain covenants, the loan will become payable at the discretion of the creditor. One of the positive covenants which must be met is the Company must maintain a minimum level of loan coverage ratios. As at March 31, 2006, the Company was not able to meet two of its five loan coverage ratios. As a result, according to the terms of the loan agreement, the loan became payable at the discretion of the creditor and the full amount of the loan has been classified as a current liability.

(2) During the year ended March 31, 2006 the performance guarantee provided by the Company and its joint-venture partner to the Government of Bangladesh in the amount of US$20 million, as specified in the production sharing agreement for Block 9, was extended to October 15, 2006. The Government of Bangladesh has the right to collect on this guarantee if the Company does not carry out specified geological, geophysical and drilling activities. The Company's portion of the guarantee is US$13.3 million. The Company considers the contingent future payment amount of US$13.3 million to be a reasonable approximation of fair value. There is risk related to the amount of contingent future payment recorded due to fluctuations in foreign exchange rates. Subsequent to March 31, 2005, Export Development Canada provided a performance security guarantee for this performance guarantee on behalf of the Company. Accordingly, the US$13.3 million previously provided by the Company for the performance guarantee was returned.

NET ASSET VALUE

March 31, 2006	($000s)	Per Share
Reserves [1]		
Proved	$ 655,171	$ 15.66
Probable	423,062	10.11
Land [2]	81,993	1.96
Working capital	(19,962)	(0.48)
Non-current monetary assets	48,938	1.17
Proceeds on dilution [3]	132,097	3.16
Total	$1,321,299	$ 31.58
Fully diluted number of shares (000s)	41,845	

(1) Based on the Gaffney, Cline & Associates and Ryder Scott forecast price cases, using 10 percent discount rate, pre-tax and internal estimates for the Bhandut Field in India and the Canadian property. NAV calculated in the same manner as above based on forecast prices and costs after tax is $28.34 per share.

(2) The Company has 1,290,994 acres of undeveloped land in India and 62,750 net acres of undeveloped land in Thailand, both of which are valued at $50 per acre. The undeveloped land in Bangladesh, 1,092,222 acres, was valued based on the purchase cost of Block 9 ($13 per acre).

(3) Includes proceeds from exercise of 3,312,500 stock options.

RISKS

In the normal course of business the Company is exposed to a variety of risks in its operations. These include operational, currency, taxation, foreign operations, commodity price, political, government policy and legislation and concentrated sales risks.

The Company is exposed to operational risks inherent in exploring for, developing and producing crude oil and natural gas. There are numerous uncertainties in estimating oil and natural gas reserves and in projecting future production and costs. Uncertainties also exist when predicting the results and timing of exploration and development projects and their related expenditures. Total amounts or timing of production may vary significantly from reserves and production estimates. The Company attempts to limit these risks by maintaining a focused asset base and by hiring qualified professionals with appropriate industry experience. A comprehensive insurance program is maintained to mitigate risks and to protect against significant losses, while maintaining levels of risk within the Company which management believes to be acceptable. This includes traditional industry coverage such as well control insurance. In addition, because of the physical concentration of production at Hazira, the Company carries business interruption insurance that, after the deductible period, would provide six months of revenue at current production levels on the land-based drilling platform wells and one year of revenue on the offshore platform wells.

The Company plans to operate in regions where the petroleum industry is a key component of the economy to help mitigate the risks of operating in foreign jurisdictions. The Company believes that management's experience operating internationally helps to further reduce these risks.

Currency risks have been reduced to primarily a U.S. dollar/Canadian dollar risk by denominating revenues in one currency, the U.S. dollar. Since June 2002, the majority of the Company's revenue is from U.S. dollar-denominated contracts. The vast majority of capital expenditures are in U.S. dollars, as is a portion of operating costs. The remaining operating costs are in local currency. The Company's financial risk profile at March 31, 2006 is described in Note 12 to the Consolidated Financial Statements.

Natural gas prices where the Company operates are generally influenced by local market supply and demand. The Company's natural gas production in India is typically sold with fixed-price contracts at U.S. dollar-equivalent prices and the Company expects to continue entering into natural gas contracts in India on this basis. The price provisions in most of the Hazira natural gas contracts expired in November 2004 and January 2005 and most of the contracts contain a renewal provision to renegotiate based on mutual agreement on market related prices. Though no formal contract has been signed, the Company has agreed to a price of US$3.65 per Mcf with four customers. The Company has signed contracts with two customers at a price of US$3.75 per Mcf and is recording revenue relating to the remaining customers at prices between US$3.45 per Mcf and US$3.65 per Mcf pending a price renegotiation. The Company's natural gas enjoys a significant price, efficiency and environmental advantage compared to naphtha, the main competing fuel. Liquefied natural gas imports have begun and are currently priced at levels consistent with market prices and are expected to be a key price determinant in the future.

Currently the Company is selling natural gas to 13 customers, down from 17 in fiscal 2005. The largest customer accounted for 22 percent of sales in both fiscal 2006 and fiscal 2005.

SUMMARY OF QUARTERLY RESULTS

The Company's activities are carried out primarily in U.S. dollars as well as the currencies of each country in which the Company operates. The Company reports financial results in Canadian dollars. The selected financial information presented below is prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP), except for funds from operations and funds from operations per share, which are used by the Company to analyze the results of operations and liquidity. By examining funds from operations, the Company is able to determine its ability to fund future capital projects and investments. Funds from operations is calculated as cash flows prior to the change in non-cash working capital related to operating activities. Funds from operations is not an alternative to cash flow from operating activities as determined in accordance with Canadian GAAP and may not be comparable with the calculation

or similar measures for other companies. The consolidated statements of cash flows in the audited consolidated financial statements present the reconciliation between net earnings and cash flow from operating activities. Funds from operations per share-diluted, is calculated by dividing the funds from operations by the weighted average number of diluted shares outstanding.

The following tables set forth selected financial information of the Company for each of the eight most recently completed quarters to March 31, 2006:

Three months ended (thousands of dollars, except per share amounts)	June 30, 2005	Sept. 30, 2005	Dec. 31, 2005	**Mar. 31, 2006**
Petroleum and natural gas sales	32,706	32,899	32,665	**22,898**
Funds from operations				
Per share				
– basic ($)	0.54	0.49	0.48	**0.26**
– diluted ($)	0.52	0.47	0.47	**0.26**
Net income (loss)	4,343	4,393	4,403	**(17,491)**
Per share				
– basic ($)	0.11	0.11	0.11	**(0.45)**
– diluted ($)	0.11	0.11	0.11	**(0.45)**

Three months ended (thousands of dollars, except per share amounts)	June 30, 2004	Sept. 30, 2004	Dec. 31, 2004	Mar. 31, 2005
Petroleum and natural gas sales	22,467	22,864	27,849	34,670
Funds from operations				
Per share				
– basic ($)	0.41	0.38	0.47	1.16
– diluted ($)	0.40	0.37	0.46	1.13
Net income	5,470	6,804	14,684	47,264
Per share				
– basic ($)	0.16	0.19	0.41	1.29
– diluted ($)	0.15	0.19	0.40	1.26

Net income has fluctuated over the quarters, in part due to changes in revenue, profit petroleum, operating expenses, foreign exchange, insurance proceeds, depletion and income tax.

Until the quarter ended December 31, 2005 revenues were positively impacted due to increased production volumes in India and Bangladesh and increased U.S. dollar sales prices in India. This increase was offset by a decrease in the price received as revenues are received in U.S. dollars and the U.S. dollar has weakened against the Canadian dollar during fiscal 2004, fiscal 2005 and fiscal 2006. In the fourth quarter of fiscal 2006, the Company's sales, net income and funds from operations decreased as the Company reduced the price at which it recognized Bangladesh natural gas sales to $1.75 per Mcf, shut-in the Feni field in Bangladesh and experienced natural declines in Hazira production. The Company shut-in the Feni field in Bangladesh in an effort to draw attention to a growing account receivable owed by the Government of Bangladesh as well as for scheduled maintenance. Net income was also reduced by increased depletion expense which resulted from decreased reserves on the producing properties and an increase in stock-based compensation expense due to stock option grants in the fourth quarter of fiscal 2006. Both net income and funds from operations decreased due to increased taxes in India resulting from refiling of prior year tax returns.

The Company's overall revenue increased during the quarter ended December 31, 2004 with the commencement of production in Bangladesh. Profit petroleum expense decreased in the last two quarters of fiscal 2004 due to deducting capital expenditures from the cash flow from Hazira prior to calculating the charge. Profit petroleum increased

throughout fiscal 2005 as capital activity in Hazira declined compared to the prior year, availing fewer deductions in the calculation. Profit petroleum increased further beginning in the third quarter of fiscal 2005 due in part to the addition of Bangladesh production.

Operating expenses in Bangladesh during the quarter ended December 31, 2005 were higher than previous quarters due to a change in the allocation of common costs that resulted in a reclassification of approximately $0.7 million from property and equipment to operating expenses.

There was a foreign exchange gain in fiscal 2005 primarily due to the strengthening of the Canadian dollar versus the U.S. dollar applied to the U.S. dollar-denominated debt. In the first quarter of fiscal 2006, there was a weakening of the Canadian dollar versus the U.S. dollar resulting in a foreign exchange loss related to the long-term debt and a gain on the funds held in U.S. dollars. In the second quarter of fiscal 2006, the Canadian dollar strengthened versus the U.S. dollar, resulting in a foreign exchange gain on the long-term debt, which was more than offset by the loss on the conversion of the U.S. dollar-held cash and the U.S. dollar receivables in excess of payables. In the third quarter of fiscal 2006, the Canadian dollar strengthened versus the U.S. dollar resulting in a foreign exchange gain on the long-term debt, which was partially offset by the loss on the conversion of the U.S. dollar-held cash and the U.S. dollar receivables in excess of payables.

In the third quarter of fiscal 2005, insurance proceeds of $3.3 million were recorded that increased net income. Depletion expense increased in fiscal 2004 and the first two quarters of fiscal 2005 due to increased production and the inclusion of the Surat exploration and Hazira development costs in the cost base. Depletion expense rose in the third quarter of fiscal 2005 because of increased production, including the commencement of production in Bangladesh. Depletion expense continued to increase in the fourth quarter of fiscal 2005 due to a technical revision in the March 31, 2005 reserve report that related to Hazira proved reserves of 39 billion cubic feet. In the second quarter of fiscal 2006, depletion expense decreased due to an internal revision to the proved reserves in Feni. The internal revision was due to the planned installation of a natural gas compressor, which is expected to increase the recoverable reserves from the existing reservoir.

There was a tax recovery in the third quarter of fiscal 2005 related to Canadian tax pools available for future claim. In the fourth quarter of fiscal 2005, there was a recovery in current and future income taxes as a result of the recognition of the benefit of a tax holiday in India. For the first three quarters of fiscal 2006, current taxes in India were being recorded at an effective rate of 14 percent. In the quarter ended March 31, 2006 there was an adjustment to Indian taxes to an effective rate of 27 percent for the year. The increase was a result of lower than expected production from the LBDP and a lower deduction for the tax holiday due to the offshore platform not yet recovering costs.

In general, funds from operations per share trend with revenue, with variations for timing differences of payments and collections.

FOURTH QUARTER

For the quarter ended March 31, 2006 the Company's sales and net income were impacted by a reduction in the Bangladesh sales price to US$1.75 per Mcf and a shut-in of the Feni field in Bangladesh in an effort to draw attention to a growing receivable owed by the Government of Bangladesh as well as for scheduled maintenance. The recognition of the Bangladesh revenue at a price of US$1.75 per Mcf for sales made during the nine months ended December 31, 2005 in the quarter ended March 31, 2006 reduced the petroleum and natural gas sales figure by CAD$3.4 million (CAD$2.7 million net of profit petroleum). The reduction in the Bangladesh sales prices to US$1.75 per Mcf for fiscal 2005 resulted in a CAD$1.2 million write-off of accounts receivable in the quarter, CAD$1.6 million year to date. Additionally, the Company estimates the shut-in of production in Bangladesh further reduced the sales for the quarter by approximately CAD$3.0 million. Sales in both India and Bangladesh decreased due to the strengthening of the Canadian dollar versus the U.S. dollar as the Company's sales prices are in U.S. dollars. These factors also decreased funds from operations.

Net income was also reduced by an increase in depletion expense. The Company experienced an increase in depletion expense due to downward revisions to reserves resulting from new information regarding well performance at the Hazira field in India.

The Company has a working capital deficiency as at March 31, 2006 of $20.0 million, which includes $39.2 million of cash and cash equivalents. The working capital deficiency is due to the reclassification of the receivable owed by the Government of Bangladesh from current and non-current, the reclassification of long-term debt to current from long-term and continued capital spending in the quarter. The income tax receivable increased due to an expected income tax recovery in India. Also, the Company made a scheduled debt repayment of US$6.68 million on its credit facility.

Capital expenditures of $33.3 million were made during the quarter. A total of $5.6 million (net) was spent in Hazira on the completion of the OS-7, OS-8 and OS-9 wells, the drilling and completion of OS-10 and oil facility construction. In Surat, there were minor additions of $0.1 million. In the D6 Block, a total of $5.6 million (net) was spent on the drilling of the MA-1 well and seismic. An additional $0.5 million was spent on 3D seismic in the NEC-25 Block in the quarter. In Bangladesh, $8.5 million was spent on site preparation for Feni-6 and Feni-7, natural gas plant and pipeline costs in Chattak and clean-up costs associated with the Chattak uncontrolled releases of natural gas. An additional $1.5 million was spent on the Feni and Chattak properties for inventory and other allocated common costs. Fourth-quarter expenditures in Block 9 were $9.4 million which primarily consisted of Bangora-1 tie-in costs and Bangora-2 drilling costs.

A total of $2.4 million was spent on various other capital activities, including acquisition and other pre-exploration and development costs in Cauvery, the D4 Block and Thailand. The Company also capitalized $0.2 million of general and administrative costs and $0.4 million of stock-based compensation expense in the quarter.

CRITICAL ACCOUNTING ESTIMATES

The Company makes assumptions in applying the following critical accounting estimates that are uncertain at the time the accounting estimate is made and may have a significant effect on the financial statements of the Company.

PROVED OIL AND NATURAL GAS RESERVES AND FULL COST ACCOUNTING

The Company follows the Canadian full cost method of accounting whereby all costs related to the exploration for and development of oil and natural gas reserves are initially capitalized and accumulated in cost centres by country. The cost centres are then depleted and depreciated using the unit-of-production method based upon proved oil and natural gas reserves. In applying the full cost method, the Company performs a cost recovery test (ceiling test), placing a limit on the carrying value of property and equipment. The carrying value is considered recoverable when the fair value, calculated as the sum of the undiscounted value of future net revenues from proved reserves, the lower of cost and market of unproved properties and the cost of major development properties, exceeds the carrying value. When the carrying value exceeds the fair value, an impairment loss is recognized to the extent that the carrying value of assets exceeds the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The net present value is estimated using expected future prices and costs and is discounted using a risk-free interest rate.

Independent qualified engineers in conjunction with the Company's reserve engineers estimate the value for oil and natural gas reserves that are used in the depletion and depreciation as well as the ceiling test calculation. This estimation is performed in accordance with the standards set forth in the Canadian Oil and Gas Evaluation Handbook.

For both the India and Bangladesh cost centres, the carrying value of the property, plant and equipment exceeded the undiscounted values of future net revenues from the Company's proved reserves. As such, an impairment was indicated for both cost centres and the Company proceeded to calculate the amount of the impairment loss. However, the calculation of the impairment loss indicated the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeded the carrying value. As such, no impairment loss was recorded in the financial statements as at March 31, 2006.

The amounts recorded for depletion and depreciation of exploration and development costs and the ceiling test are based on estimates of proved reserves, production rates, future oil and natural gas prices and future costs, which are all subject

to measurement uncertainties and various interpretations. The Company expects that its estimates of reserves will be revised upwards or downwards over time, based on future changes to these variables. Reserve estimates can have a material impact on the depletion and depreciation expense and the carrying value of property and equipment. Revisions to reserve estimates could increase or decrease depletion and depreciation expense charged to net income and a decrease in estimated reserves could result in a write-down of property and equipment based on the ceiling test in the future.

COSTS EXCLUDED FROM DEPLETABLE BASE

Costs of acquiring unproved properties are initially excluded from the full cost pool and are assessed quarterly to ascertain whether impairment has occurred. When proved reserves are assigned to the property or the property is considered to be impaired, the cost of the property or the amount of impairment is added to the full cost pool. Costs of major development projects are initially excluded from the full cost pool and are assessed quarterly to ascertain whether impairment has occurred. When a portion of the property becomes capable of commercial production or the property is considered to be impaired, the cost of the property is added to the full cost pools.

ASSET RETIREMENT OBLIGATION

As the Company's assets are retired, significant abandonment and reclamation costs will be incurred. The Company recognizes the fair value of a liability for an asset retirement obligation with a corresponding amount capitalized to property and equipment. The liability increases and accretion expense is recognized each period due to the passage of time. The capitalized portion is depleted based on the unit-of-production method.

The obligation is based on factors including current regulations, abandonment costs, technologies, industry standards and obligations in the Company's agreements. The fair value calculation takes into account estimated timing of abandonment, inflation and a credit-adjusted, risk-free interest rate. Changes in any of the factors and revisions to any of the estimates used in calculating the obligation may result in a material impact to the carrying value of property and equipment, asset retirement obligation and depletion expense charged to net income. The Company expects that its estimates of its asset retirement obligations will be revised upwards or downwards over time, based on future changes to the factors and estimates involved. Changes to these estimates in the past have not resulted in material adjustments to the financial statements.

REVENUE RECOGNITION

The Company has reached an agreement with the Government of Bangladesh to sell up to 50 million cubic feet per day and is currently in discussions with the Government of Bangladesh in an attempt to finalize the natural gas sales price. From inception, up to and including the quarter ended September 30, 2005, the Company had recorded natural gas revenue at a price of US$2.20 per Mcf. During the quarter ended December 31, 2005 the Company changed its estimate of the natural gas sales price to US$2.10 per Mcf. The Company is currently recording Bangladesh natural gas sales since inception at a price of US$1.75 per Mcf based on negotiations with the Government. Overall, the reduction in the Bangladesh natural gas sales prices from US$2.20 per Mcf to US$1.75 per Mcf reduced revenue by CAD$4.4 million. The recognition of sales at a price of US$1.75 per Mcf resulted in a further decrease in Bangladesh sales of CAD$3.4 million.

The actual natural gas price received by the Company may differ from US$1.75 and as such revenue, profit petroleum and accounts receivable could be materially impacted.

STOCK-BASED COMPENSATION

The Company uses the fair value method of accounting for its stock-based compensation expense associated with its stock option plan. Compensation expense is based on the fair value of stock options at the grant date using a Black-Scholes option-pricing model. The Black-Scholes model requires estimates for the expected volatility of the Company's stock, a risk-free interest rate, expected dividends on the stock and expected life of the option. Changes in these estimates may result in the actual compensation expense being materially different than the compensation expense recognized; however, this expense is not subsequently adjusted for changes in these factors. The Company capitalizes the stock-based compensation expense relating to those employees whose time relates to exploration activities.

INCOME TAXES

The Company follows the tax liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs.

The Company's current and future income tax liability involves interpretation of complex laws and regulations involving multiple jurisdictions. The Company pays income tax at the highest rate of the jurisdictions in which it operates. This is subject to changing laws and regulations and tax filings are subject to audit and potential reassessment. The Company expects that its estimates of current and future income tax liability will be revised upwards or downwards over time, based on changes in the reversal of timing differences, enacted income tax rates, laws and regulations and reassessment of tax filings.

ACCRUAL ACCOUNTING

The Company follows the accrual method of accounting, making estimates in its financial and operating results. This may include estimates of revenues, royalties, production and other expenses and capital items related to the period being reported, for which actual results have not yet been received. The Company expects that its accrual estimates will be revised, upwards or downwards, based on the receipt of actual results.

FINANCIAL INSTRUMENTS

To protect against foreign exchange fluctuations in connection with the proposed sale of the Bhandut, Cambay and Sabarmati properties, the Company entered into a foreign exchange forward contract whereby it committed to sell US$5.5 million to the counterparty on or before May 28, 2006. The contract has been recorded at fair value and the loss associated with it has been recorded in income in the current year.

Financial instruments of the Company consist of cash, restricted cash, prepaid expenses, accounts receivable, investments, accounts payable, accrued liabilities, bank indebtedness and a forward exchange contract. As at March 31, 2006 and 2005 there were no significant differences between the carrying amounts of these instruments and their fair values.

The Company is exposed to floating interest rates with respect to its bank facility. The Company is also exposed to fluctuations in exchange rates due to the nature of the Company's operations as its revenue is in both Indian Rupees and U.S. dollars. Under the terms of the long-term debt agreement, the Company cannot manage its exposure to foreign exchange risk.

A portion of the Company's accounts receivable are with organizations in the oil and natural gas industry and are subject to normal industry credit risks. Most purchasers of the Company's oil and natural gas production are subject to an internal credit review and must provide financial performance guarantees in order to minimize the risk of non-payment. Natural gas is typically sold under fixed-price, fixed-term contracts while oil is sold at prevailing world market prices.

DISCLOSURE CONTROLS AND PROCEDURES

The Company's Chief Executive Officer and Controller have evaluated the effectiveness of Niko's disclosure controls and procedures as of March 31, 2006. Based on that evaluation, the Chief Executive Officer and the Controller have concluded that the Company's disclosure controls were effective in ensuring material information required to be disclosed by the Company in its annual filings or other reports filed or submitted under applicable Canadian securities laws is made known to management on a timely basis to allow decisions regarding required disclosure.

OUTSTANDING SHARE DATA

At June 26, 2006, the Company had the following outstanding shares:

	Number	Amount
Common shares	38,568,570	$ 308,715,965
Preferred shares	nil	nil
Stock options	3,048,750	–

MANAGEMENT'S REPORT

All information in this Annual Report is the responsibility of management. The financial statements necessarily include amounts that are based on estimates, which have been objectively developed by management using all relevant information. The financial information contained elsewhere in this report has been reviewed to ensure consistency with the financial statements.

Management maintains a system of internal accounting controls designed to provide reasonable assurance that assets are safeguarded, transactions are properly authorized and financial records are properly maintained to provide reliable information for the preparation of financial statements.

The Audit Committee of the Board of Directors, comprised of non-management directors, has reviewed the financial statements with management and KPMG. The financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

Edward S. Sampson
President and CEO

Mark Dantzer
Controller

June 26, 2006

AUDITORS' REPORT

To the Shareholders of Niko Resources Ltd.

We have audited the consolidated balance sheets of Niko Resources Ltd. as at March 31, 2006 and 2005 and the consolidated statements of operations and retained earnings and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at March 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP.

KPMG LLP
Chartered Accountants
Calgary, Canada
June 26, 2006

CONSOLIDATED BALANCE SHEETS

AS AT MARCH 31 (THOUSANDS OF DOLLARS)

	2006	2005
ASSETS		
Current assets		
Cash and cash equivalents	$ 39,197	$ 101,957
Accounts receivable (note 3)	37,011	46,219
Prepaid expenses	622	303
	76,830	148,479
Restricted cash (note 17)	15,563	–
Long-term account receivable (note 4)	17,412	–
Income tax receivable	15,963	12,961
Property and equipment (note 5)	391,490	319,274
	$ 517,258	$ 480,714
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	$ 67,412	$ 40,694
Current portion of long-term debt (note 7)	28,523	7,088
Current tax payable	857	326
	96,792	48,108
Asset retirement obligation (note 6)	6,779	4,644
Long-term debt (note 7)	–	14,418
	103,571	67,170
Shareholders' equity		
Share capital (note 8)	297,747	294,297
Contributed surplus (note 9)	6,861	1,212
Retained earnings	109,079	118,035
	413,687	413,544
	$ 517,258	$ 480,714

Commitments (note 15)
Contingencies (note 18)
Subsequent events (note 19)

See accompanying Notes to Consolidated Financial Statements.

Approved by the Board,

Robert R. Hobbs
Director

Edward S. Sampson
Director

CONSOLIDATED STATEMENTS *of* OPERATIONS *and* RETAINED EARNINGS

YEARS ENDED MARCH 31, (THOUSANDS OF DOLLARS, EXCEPT PER SHARE AMOUNTS)

	2006	2005
Revenue		
Oil and natural gas	$ 121,168	$ 107,850
Royalties	(17,443)	(16,553)
Profit petroleum	(11,828)	(9,050)
Pipeline and other	4,119	2,169
	96,016	84,416
Expenses		
Production and pipeline	9,756	8,903
Interest and financing	3,675	1,622
General and administrative	5,448	3,613
Write-down of long-term account receivable (note 4)	1,631	–
Foreign exchange (gain) loss	44	(1,861)
Insurance proceeds (note 16)	–	(3,333)
Stock-based compensation	5,318	1,297
Depletion and depreciation	65,883	35,956
	91,755	46,197
Income before income taxes	4,261	38,219
Current	8,613	(13,782)
Future	–	(22,221)
	8,613	(36,003)
Net income (loss)	(4,352)	74,222
Retained earnings, beginning of year	118,035	48,167
Dividends paid	(4,604)	(4,354)
Retained earnings, end of year	$ 109,079	$ 118,035
Net income (loss) per share (note 11)		
Basic	$ (0.11)	$ 2.08
Diluted	$ (0.11)	$ 2.03

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS *of* CASH FLOWS

YEARS ENDED MARCH 31, (THOUSANDS OF DOLLARS, EXCEPT PER SHARE AMOUNTS)

	2006	2005
Cash provided by (used in):		
Operating activities		
Net income (loss)	$ (4,352)	$ 74,222
Add items not involving cash from operations		
Depletion and depreciation	65,883	35,956
Future income taxes		(22,221)
Unrealized foreign exchange (gain) loss	778	(1,861)
Stock-based compensation	5,318	1,297
Funds from operations	67,627	87,393
Change in non-cash working capital	(28,651)	(16,244)
	38,976	71,149
Financing		
Proceeds from issuance of shares, net of issuance costs (note 8)	3,053	175,659
Long-term debt	9,119	(2,698)
Dividends paid	(4,604)	(4,354)
	7,568	168,607
Investing activities		
Addition of property and equipment	(135,236)	(119,105)
Restricted cash contributions	(38,672)	–
Release of restricted cash	22,690	–
Change in non-cash working capital	43,573	(39,012)
	(107,645)	(158,117)
Increase (decrease) in cash and cash equivalents	(61,101)	80,742
Effect of translation on foreign currency cash and cash equivalents	(1,659)	(897)
Cash and cash equivalents, beginning of year	101,957	21,215
Cash and cash equivalents, end of year	$ 39,197	$ 101,957
Supplemental information:		
Interest paid	$ 3,183	$ 3,049
Taxes paid	$ 11,841	$ 3,941

See accompanying Notes to Consolidated Financial Statements.

1. COMPANY ACTIVITIES

Niko Resources Ltd's (the Company) business consists of the exploration for and development of petroleum and natural gas. The Company's business is carried on primarily in India, Bangladesh, Thailand and Canada.

The consolidated financial statements of the Company have been prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP).

2. ACCOUNTING POLICIES

(a) Principles of Consolidation

The consolidated financial statements include the accounts of the Company and all of its subsidiaries. Substantially all of the exploration and production activities of the Company are conducted jointly with others and accordingly, these financial statements reflect only the Company's proportionate interest in such activities.

(b) Cash and Cash Equivalents

Cash and cash equivalents consist of cash and demand deposits.

(c) Restricted Cash

Restricted cash consists of amounts provided as performance guarantees in accordance with production sharing contracts with host Governments entered into by the Company.

(d) Exploration and Development Costs

The Company follows the Canadian full cost method of accounting whereby all costs related to the exploration for and development of oil and natural gas reserves are initially capitalized and accumulated in cost centres by country. Costs capitalized include land and acquisition costs, geological and geophysical expenses, costs of drilling productive and non-productive wells, gathering and production facilities and equipment, and administrative costs related to capital projects. Gains or losses are not recognized upon disposition of oil and natural gas properties unless such disposition would alter the depletion rate by 20 percent or more.

In applying the full cost method, the Company performs a cost recovery test (ceiling test), placing a limit on the carrying value of property and equipment. The carrying value is considered recoverable when the fair value, calculated as the sum of the undiscounted value of future net revenues from proved reserves, the cost of unproved properties and the cost of major development properties, exceeds the carrying value. When the carrying value exceeds the fair value, an impairment loss is recognized to the extent that the carrying value of assets exceeds the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The net present value is estimated using expected future prices and costs and is discounted using a risk-free interest rate.

(e) Capitalized Interest

Interest costs on major capital projects are capitalized until the projects are capable of commercial production. These costs are subsequently amortized with the related assets.

(f) Asset Retirement Obligation

The Company recognizes the fair value of a liability for an asset retirement obligation in the period in which it is incurred or when a reasonable estimate of fair value can be made. The fair value of an asset retirement obligation is recorded as a liability and a corresponding increase in property and equipment and is depleted based on the unit-of-production method. The liability increases and accretion expense are recognized each period due to the passage of time. Subsequent to

initial measurement, period-to-period changes in the liability are recognized for revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Actual costs incurred upon settlement are charged against the asset retirement obligation. Any difference between the actual costs and the recorded liability is recognized as a gain or loss in earnings in the period in which the settlement occurs.

(g) Revenue Recognition

Sales of crude oil, natural gas and natural gas liquids are recorded in the period in which the title to the petroleum transfers to the customer. Crude oil and natural gas liquids produced, but unsold, are recorded as inventory until sold.

(h) Depletion and Depreciation

Costs of acquiring unproved properties are initially excluded from the full cost pool and are assessed quarterly to ascertain whether impairment has occurred. When proved reserves are assigned to the property or the property is considered to be impaired, the cost of the property or the amount of impairment is added to the full cost pool. Costs of major development projects are initially excluded from the full cost pool and are assessed quarterly to ascertain whether impairment has occurred. When a portion of the property becomes capable of commercial production or the property is considered to be impaired, the cost of the property is added to the full cost pools.

Costs capitalized are depleted using the unit-of-production method by cost centre based upon net proved oil and natural gas reserves as determined by independent engineers. For purposes of the calculation, oil and natural gas reserves are converted to a common unit of measure on the basis of their relative energy content.

Office and other equipment are depreciated using the declining balance method at rates of 20 percent to 30 percent per annum.

(i) Foreign Currency

Accounts of foreign operations, all of which are considered financially and operationally integrated, are translated to Canadian dollars using average exchange rates for the year for revenue and expenses. Monetary assets and liabilities are translated at the year-end current exchange rate and non-monetary assets and liabilities are translated using historical rates of exchange. Gains or losses resulting from these translation adjustments are included in net income for the year.

Transactions in foreign currencies are translated at rates in effect at the time of the transaction. Monetary assets and liabilities are translated at current rates. Gains and losses are included in income. Gains and losses related to long-term monetary assets and liabilities are considered to be unrealized and a non-cash item for the purposes of the statement of cash flow preparation.

(j) Financial Instruments

The Company from time to time employs financial instruments to manage exposures related to Canada/U.S. dollar exchange rates. These instruments are not used for speculative trading purposes.

The Company's risk management policy includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company believes the derivative financial instruments are effective as hedges, both at inception and over the term of the instrument, when the term and notional amount do not exceed the firm commitment or forecasted transaction and the underlying basis of the instrument, the foreign exchange rate, correlates highly with the Company's exposure.

The Company may enter into foreign exchange forward contracts to hedge anticipated U.S. dollar-denominated petroleum and natural gas sales. These derivatives, accounted for as hedges, are not recognized on the balance sheet. The gains and losses on these derivatives are recognized as an adjustment to petroleum and natural gas revenues when the revenue is recognized.

Gains and losses resulting from changes in the fair value of derivative contracts that do not qualify for hedge accounting are recognized in earnings when those changes occur.

The Company does not have any financial instruments that qualify for hedge accounting.

(k) Income Taxes

The Company follows the tax liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs.

(l) Measurement Uncertainty

The preparation of the financial statements in conformity with Canadian Generally Accepted Accounting Principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. By their nature, these estimates are subject to measurement uncertainty and actual results may differ from those estimates.

The most significant estimates made by management relate to amounts recorded for the depletion of capital assets, the provision for the asset retirement obligation and accretion expense and the ceiling test. The ceiling test calculation and the provisions for depletion and asset retirement obligation are based on such factors as estimated proved reserves, production rates, petroleum and natural gas prices and future costs. Future events could result in material changes to the carrying values recognized in the financial statements.

(m) Per Share Amounts

Basic earnings per share are computed by dividing earnings by the weighted average number of common shares outstanding during the year. Diluted per share amounts reflect the potential dilution that could occur if options or warrants to purchase common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments.

(n) Stock-based Compensation Plans

The Company has a stock-based compensation plan described in note 8. Effective April 1, 2003 compensation expense associated with the plan is calculated and recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. Compensation expense is based on the fair value of the stock options at the grant date using a Black-Scholes option-pricing model. Any consideration received upon exercise of the stock options, together with the amount previously recognized in contributed surplus, is recorded as an increase to share capital.

(o) Comparative Figures

Certain comparative figures have been reclassified to conform to the current year's presentation.

3. ACCOUNTS RECEIVABLE

As described below the Company has two significant accounts receivable.

(a) There are 12 contracts for the sale of natural gas from the Hazira field. Most of the natural gas contracts are U.S. dollar-denominated and the price had been at the Indian Rupee equivalent of US$3.45 per Mcf while spot sales were at US$3.75 per Mcf. The price provisions in most of the contracts expired in November 2004 and January 2005 and most of the contracts contain a renewal provision to renegotiate based on mutual agreement on market related prices. Though no formal contracts have been signed, the Company has agreed to a price of US$3.65 per Mcf with four customers. The Company has signed contracts with two customers at a price of US$3.75 per Mcf and recording revenue relating to the remaining customers at prices between US$3.45 per Mcf and US$3.65 per Mcf until a new price can be negotiated. Certain customers are not paying the incremental increase in price and are paying at the previously negotiated price of US$3.45 per Mcf. The total amount of the incremental price increases still under negotiation is CAD$0.4 million.

(b) With respect to the uncontrolled releases of natural gas which occurred while drilling the Chattak-2 well and the subsequent relief well Chattak-2A in January and June 2005, respectively, the Company had a control of well insurance policy with US$20.0 million of coverage for each of the wells. Costs totaling US$22.9 million have been submitted to the insurers related to the first blowout and US$19.6 million had been received as at March 31, 2006. Costs to control the second blowout include drilling of the data acquisition well, Chattak-2C, and the relief well, Chattak-2B. These costs total US$55.8 million to the end of March 31, 2006 and have been submitted to the insurers; US$6.1 million had been received as at March 31, 2006. Subsequent to March 31, 2006, the Company received US$8.5 million under the second insurance policy.

4. LONG-TERM ACCOUNT RECEIVABLE

The long-term account receivable balance consists of the receivable charged to Petrobangla (the Bangladesh Oil, Gas and Mineral Corporation) for production from the Feni field in Bangladesh. Since the commencement of production in November 2004, the Company has been delivering all of its gas and condensate production in Bangladesh to Petrobangla. The Company has received two payments totaling US$4 million since the commencement of production.

From inception up to and including the quarter ended September 30, 2005, the Company had recorded gas revenue and valued the receivable at a price of US$2.20 per mcf. During the quarter ended December 31, 2005, the Company made an adjustment to record the revenue since inception and value the receivable at a price of US$2.10 per Mcf based on correspondence with Petrobangla. Negotiations have continued with Petrobangla stating they will only accept US$1.75 per Mcf. On April 24, 2006 the Company responded to Petrobangla indicating they will agree to US$1.75 per Mcf if Petrobangla would agree to use international arbitration to settle the issues discussed in note 18. (b) and (c) Contingencies.

Revenue since inception has been adjusted and is recorded at a price of US$1.75 per Mcf and included in accounts receivable is US$14.9 million (CAD$17.4 million) outstanding from this customer. The write-down of accounts receivable of CAD$1.631 million is the result of the recognition of the prior year's revenue at a price of US$1.75 per Mcf.

The Company is not certain the collection of this receivable will occur within one year from March 31, 2006; as such, the receivable has been classified as long-term. In previous periods, the receivable was classified as accounts receivable in current assets.

Refer to note 18. (b) and (c), Contingencies, for further discussion regarding the Company's ability to collect this receivable.

5. PROPERTY AND EQUIPMENT

2006 (thousands)		**Cost**		**Accumulated Depletion and Depreciation**		**Net Book Value**
Oil and natural gas						
India	$	331,380	$	115,163	$	216,217
Bangladesh		190,213		17,990		172,223
Thailand		1,370		–		1,370
Canada		1,900		1,268		632
Corporate		1,354		306		1,048
	$	526,217	$	134,727	$	391,490

2005 (thousands)		Cost		Accumulated Depletion and Depreciation		Net Book Value
Oil and natural gas						
India	$	285,374	$	62,033	$	223,204
Bangladesh		99,717		5,837		93,880
Canada		1,859		1,075		784
Corporate		1,655		249		1,406
	$	388,468	$	69,194	$	319,274

During the year, the Company capitalized $0.9 million of general and administrative expenses and $0.7 million of stock-based compensation expense (2005 – nil).

Costs of $181,990,000 (2005 – $135,848,000), associated with the Company's undeveloped properties in India, Bangladesh and Thailand, have been excluded from costs subject to depletion and depreciation.

Subsequent to March 31, 2006 the Company obtained a new cost centre, Thailand, in which planned principal operations have not commenced. Activities related to exploration and development for oil and natural gas are considered to be in the preproduction stage. All costs related to this cost centre have been capitalized. Pre-acquisition costs of $1,370,000 (2005 – nil) have been incurred to date with respect to the Company's unproven property in Thailand.

During the quarter ended March 31, 2006, the Company entered into a Purchase and Sale agreement for the sale of its interests in the Bhandut, Cambay and Sabarmati oil fields located onshore India. The aggregate sale price for these fields is US$5.5 million. The completion of the sale is subject to approval from the Government of India.

At March 31, 2006 the Company performed a "ceiling test" for the Indian, Bangladesh and Canadian cost centres to assess the recoverable value. The D6, NEC-25, D4 and Cauvery blocks in India and the Chattak block in Bangladesh have been excluded from the ceiling test as the Company considers these properties to be either major development projects or unproved properties.

For the India and Bangladesh cost centre, the carrying value of the property, plant and equipment exceeded the undiscounted values of future net revenues from the Company's proved reserves. This indicated an impairment and the Company proceeded to calculate the amount of the impairment loss. However, the calculation of the impairment loss indicated the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the

lower of cost and market of unproved properties and the cost of major development projects, exceeded the carrying value. Accordingly, no impairment loss was recorded in the financial statements as at March 31, 2006 for either cost centres.

The undiscounted value of future net revenues from the Company's proved reserves exceeded the carrying value of property, plant and equipment for the Canada cost centres at March 31, 2006.

The future oil and condensate prices for Hazira, Surat, Feni and Block 9 are based on the April 1, 2006 commodity price forecast relative to Brent blend prices of our independent reserve evaluators and are adjusted for commodity price differentials specific to the Company. For the prices quoted in U.S. dollars, the Company converted the prices to Canadian dollars using the exchange rate provided by its independent reserves evaluators. The future oil price for Canada is based on the March 2006 actual selling price as an independent reserve evaluation was not performed due to the size of the Canadian operations relative to the Company. The Canadian operations accounted for less than 1 percent of sales for the year ended March 31, 2005. The natural gas price is based on contracts entered into by the Company and forecasts of future contract prices. The table below summarizes the benchmark prices used in the ceiling test calculation.

	Hazira Oil Prices	Hazira Natural Gas Prices	Surat Natural Gas Prices	Feni Condensate Prices	Feni Natural Gas Prices	Foreign Exchange Rate	Canada Oil Prices	Block 9 Natural Gas Prices
	(US$/bbl)	(US$/Mcf)	(US$/Mcf)	(US$/bbl)	(US$/Mcf)	(USD/CAD)	(CAD$/bbl)	(US$/Mcf)
2007	55.00	3.76	3.19	40.00	1.75	0.85	55.50	2.50
2008	53.31	4.34	4.16	40.00	1.75	0.85	55.50	2.50
2009	46.98	4.58	4.39	40.00	1.75	0.85	55.50	2.50
2010	43.30	4.83	4.63	40.00	1.75	0.85	55.50	2.50
2011	41.71	5.07	4.86	40.00	1.75	0.85	55.50	2.50
Thereafter	40.65	6.27	6.01	40.00	1.75	0.85	55.50	2.50

6. ASSET RETIREMENT OBLIGATION

The asset retirement obligation relates to the future site restoration and abandonment costs including the costs of production equipment removal and environmental clean-up based on regulations and economic circumstances at year-end. The fair value of the asset retirement obligation is estimated at $6.779 million as at March 31, 2006 (March 31, 2005 – $4.644 million).

The following table reconciles the Company's asset retirement obligations at the end of each year:

(thousands)	2006	2005
Obligation, beginning of year	$ 4,644	$ 553
Obligation incurred during the year	1,078	1,972
Revision in estimated cash flows	706	1,896
Accretion expense	351	223
Obligation, end of year	$ 6,779	$ 4,644

The Company has estimated the fair value of its total asset retirement obligations based on an estimated future liability of $10,894,745 discounted, using a credit-adjusted, risk-free rate of 7 percent. The costs are expected to be incurred between 2012 and 2020.

7. LONG-TERM DEBT

A project facility (the facility) was established to fund the Company's development activities on India's west coast, specifically the Hazira offshore platform project and the Surat development project. At March 31, 2005, the facility limit was US$30 million, of which US$20 million was drawn. During the year ended March 31, 2006 the loan amount was expanded from US$30 million to US$40 million as certain financial and operational criteria were met at Hazira and the remaining US$20 million was drawn. The first repayment of the loan occurred on March 15, 2005 based on 11.1 percent (US$2.22 million) of the US$20 million outstanding at that time. On September 15, 2005 the Company made a repayment for 11.1 percent (US$2.22 million) of the second US$20 million drawn plus 11.1 percent (US$4.44 million) of the total amount drawn of US$40 million. On March 15, 2006 the Company made a repayment for 16.7 percent (US$6.68 million) of the total amount drawn. As at March 31, 2006 US$24.44 million was outstanding. There will be four more semi-annual repayments on March 15 and September 15 of each year; the next installment will be for 16.7 percent (US$6.68 million) of the total amount drawn (US$40 million) and the remaining three installments for 14.8 percent (US$5.92 million) of the total amount drawn (US$40 million). Interest is payable semi-annually on March 15 and September 15 and accrues at the London Inter Bank Offered Rate (LIBOR) plus 4.5 percent from the date of draw-down (LIBOR plus 3 percent once security is perfected).

The security will be perfected once the Management Committee of the Hazira property, which is comprised of members of the Company and its joint-venture partner as well as the Indian Government, gives its formal approval.

If the Company fails to meet certain covenants, the loan will become payable at the discretion of the creditor. One of the positive covenants which must be met is the Company must maintain a minimum level of loan coverage ratios. As at March 31, 2006, the Company was not able to meet 2 of its 5 loan coverage ratios. As a result, according to the terms of the loan agreement, the loan became payable at the discretion of the creditor and the full amount of the loan has been classified as a current liability.

8. SHARE CAPITAL

(a) Authorized

Unlimited number of common shares

Unlimited number of preferred shares

(b) Issued

(thousands of dollars, except share amounts)	2006 Number	2006 Amount	2005 Number	2005 Amount
Common shares				
Balance, beginning of period	38,286,570	$ 294,297	33,542,820	$ 118,338
Issued for cash pursuant to public offering	–	–	4,000,000	171,000
Stock options exercised	246,250	3,053	743,750	12,767
Contributed surplus	–	397	–	300
Share issue costs	–	–	–	(8,108)
	38,532,820	$ 297,747	38,286,570	$ 294,297

NOTES

(c) Stock Options

The Company has reserved for issue 3,581,750 common shares for granting under option to directors, officers, and employees. The options become 100 percent vested one to four years after the date of grant and expire four to five years after the date of grant. Stock option transactions for the respective years were as follows:

	2006 Number of Options		2006 Weighted Average Exercise Price	2005 Number of Options		2005 Weighted Average Exercise Price
Outstanding, beginning of period	1,979,250	$	26.42	2,540,000	$	19.92
Granted	1,654,500		51.78	533,000		41.70
Expired	–		–	(350,000)		22.20
Forfeited	(75,000)		37.52	–		–
Exercised	(246,250)		12.39	(743,750)		17.17
Outstanding, end of period	3,312,500	$	39.88	1,979,250	$	26.42
Exercisable, end of period	934,500	$	24.84	720,000	$	18.32

The following table summarizes stock options outstanding and exercisable under the plan at March 31, 2006.

	Outstanding Options				Exercisable Options		
Exercise Price	Options	Remaining (Years)		Weighted Average Price	Options		Weighted Average Price
$ 22.20 – $ 26.47	1,168,750	1.9	$	22.57	807,500	$	22.38
$ 27.85 – $ 39.30	216,250	3.1	$	35.23	58,750	$	34.64
$ 41.00 – $ 49.30	533,000	4.2	$	43.55	68,250	$	45.50
$ 53.70	1,394,500	3.3	$	53.70	–	$	–
	3,312,500	3.2	$	39.88	934,500	$	24.84

STOCK-BASED COMPENSATION

Prior to April 1, 2003 the Company did not record compensation expense when stock options were issued to employees, officers and directors. Had compensation cost for stock options granted to employees been determined based on a fair value method, the net earnings and earnings per share would approximate the following pro forma amounts:

(thousands of dollars, except per share amounts)		2006		2005
Stock-based compensation	$	3,646	$	3,646
Net income				
As reported	$	(4,352)	$	74,222
Pro forma	$	(7,998)	$	70,576
Net income per common share				
Basic				
As reported	$	(0.11)	$	2.08
Pro forma	$	(0.21)	$	1.98
Diluted				
As reported	$	(0.11)	$	2.03
Pro forma	$	(0.21)	$	1.93

The pro forma amounts include the compensation costs associated with stock options granted between April 1, 2002 and 2003. The fair value of each option granted was estimated on the date of grant using the Modified Black-Scholes option-pricing model with the following assumptions:

MODIFIED BLACK-SCHOLES ASSUMPTIONS

Year ended March 31 (weighted average)	2006	2005
Fair value of stock options granted (per option)	$ 14.49	$ 8.78
Risk-free interest rate	3.11%	2.93%
Volatility	38%	36%
Expected life (years)	4	4
Expected annual dividend per share	$ 0.12	$ 0.12

9. CONTRIBUTED SURPLUS

As at March 31 (thousands of dollars)	2006	2005
Contributed surplus, beginning of period	$ 1,212	$ 215
Stock-based compensation	6,046	1,297
Stock options exercised	(397)	(300)
Contributed surplus, end of period	$ 6,861	$ 1,212

10. SEGMENTED INFORMATION

The Company's operations are conducted in one business segment, the oil and natural gas industry. Revenues, operating profits and net identifiable assets by geographic segments are as follows:

Year ended March 31 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
2006						
Revenue	100,533	19,689	–	946	–	121,168
Segment profit	15,657	1,195	–	447	(56)	17,243
(thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
2005						
Revenue	96,500	10,929	–	421	–	107,850
Segment profit	36,879	1,446	–	44	(2)	38,367
(thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
2006						
Property and equipment	216,217	172,223	1,370	632	1,048	391,490
Total assets	260,218	208,220	1,370	867	46,583	517,258
(thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
2005						
Property and equipment	222,719	93,880	–	784	1,891	319,274
Total assets	267,371	117,334	–	913	95,096	480,714

NOTES

The reconciliation of the segment profit to net income as reported in the financial statements is as follows:

Year ended March 31 (thousands of dollars)	2006	2005
Segment profit	17,243	38,367
Interest and other income	3,134	1,190
Financing	(3,675)	(1,622)
Administrative expenses	(5,448)	(3,613)
Write-down of accounts receivable	(1,631)	–
Stock-based compensation	(5,318)	(1,297)
Insurance proceeds	–	3,333
Foreign exchange gain (loss)	(44)	1,861
Income tax expense	(8,613)	36,003
Net income	(4,352)	74,222

11. PER SHARE DATA

	2006	2005
Weighted average number of common shares outstanding	38,335,945	35,657,403
Weighted average number of diluted shares outstanding	38,488,978	36,540,795

12. INCOME TAXES

The provision for income taxes in the financial statements differs from the result that would have been obtained by applying the combined federal and provincial tax rate to the Company's earnings before income taxes. This difference results from the following items:

Year ended March 31 (thousands)	2006	2005
Income before income taxes	$ 4,261	$ 38,219
Statutory income tax rate	32.12%	32.12%
Computed expected income taxes	1,369	12,276
Non-deductible expenses and other	2,155	(783)
Recognition of new tax pools in the year	220	(757)
Recognition of tax holiday	(9,482)	(46,739)
Valuation allowance	14,351	–
Provision for income taxes	$ 8,613	$ (36,003)

The components of the Company's future income tax liability at March 31 are as follows:

(thousands)	2006	2005
Future income tax assets		
Asset retirement obligation	$ 2,178	$ 1,492
Unused losses	7,494	5,105
Unused foreign tax credits	8,001	4,031
Share issue expenses	1,842	2,583
Property and equipment	4,505	218
Long-term account receivable	–	75
	$ 24,020	$ 13,504
Future income tax liabilities		
Property and equipment	2,319	6,264
Long-term debt	550	340
Valuation allowance	21,106	6,900
Long-term account receivable	45	–
	$ 24,020	13,504
Net future income tax liability	$ –	$ –

India's federal tax law contains a seven-year tax holiday provision that pertains to the commercial production or refining of petroleum and natural gas substances. The benefit of the Indian tax holiday is preserved in the Canadian tax system through a tax sparing provision of the Canada-India Tax Convention.

As a result of the tax holiday in India, the Company pays the greater of 41.82 percent of net income in India after a deduction for the tax holiday and minimum alternative tax of 10.455 percent (2005 – 7.84 percent) of Indian income.

In the current year, production from the land-based drilling platform was lower than previously expected and the offshore platform has not yet recovered costs, therefore is still using regular tax deductions, resulting in a lower deduction for the tax holiday. As a result, the Company recorded current income taxes at a rate of 41.82 percent of net income after a deduction related to the tax holiday, resulting in an effective current tax rate in India of 27 percent for the quarter and year to date.

Taxes in Bangladesh are 4 percent of net revenues (revenue less profit petroleum).

13. FINANCIAL INSTRUMENTS

Financial instruments of the Company consist of cash, restricted cash, prepaid expenses, accounts receivable, investments, accounts payable, accrued liabilities, bank indebtedness and a foreign exchange forward contract. To protect against foreign exchange fluctuations in connection with the proposed sale of the Bhandut, Cambay and Sabarmati properties, the Company entered into a foreign exchange forward contract whereby it was committed to sell US$5.5 million to the counterparty on or before May 28, 2006. The contract has been recorded at fair value and the loss associated with it has been recorded in income in the current year. As at March 31, 2006 and 2005 there were no significant differences between the carrying amounts of these instruments and their fair values.

The Company is exposed to floating interest rates with respect to its bank facility. The Company is also exposed to fluctuations in exchange rates due to the nature of the Company's operations as its revenue is in both Indian Rupees and U.S. dollars. Under the terms of the long-term debt agreement, the Company cannot manage its exposure to foreign exchange risk.

A portion of the Company's accounts receivable are with organizations in the oil and natural gas industry and are subject to normal industry credit risks. Certain purchasers of the Company's oil and natural gas production are subject to an internal credit review and must provide financial performance guarantees in order to minimize the risk of non-payment. Natural gas is sold under fixed-price, fixed-term contracts while oil is sold at prevailing world market prices.

14. ECONOMIC DEPENDENCE

During the year ended March 31, 2006 three customers purchasing production from India and one customer purchasing production from Bangladesh accounted for more than 61 percent of revenue and each of these customers individually accounted for more than 10 percent of revenue. During the year ended March 31, 2005 four customers purchasing production from India and one customer purchasing production from Bangladesh each accounted for more than 10 percent of revenue and in total 69 percent of revenue. During the year ended March 31, 2006 one customer accounted for 22 percent of revenue (March 31, 2005 – 15 percent).

15. COMMITMENTS

The Company and its partner are currently in arbitration with the Government of India with respect to the cost recovery status of the investment in the 36-inch pipeline at Hazira. If successful in the arbitration, the Company would reduce its Profit petroleum payments currently being made. Additionally, in October 2002, Gujarat State Petroleum Company Ltd. (GSPCL) and the Company signed a Memorandum of Understanding in which GSPCL agreed to transfer the rights of the 36-inch pipeline to the joint venture. At March 31, 2006 the Company is still in the process of obtaining the legal title to the 36-inch pipeline. For the year ended March 31, 2006 the Company included the 36-inch pipeline in property and equipment at the net book value of $6,422,000 (2005 – $7,592,000), a net payable to GSPC of $5,408,000 (2005 – $7,091,000) and a net operating loss, calculated as net accrued revenues after operating costs and depreciation of $1,014,000 (2005 – net operating gain of $501,000) with respect to the pipeline.

All of the Company's natural gas sales contracts contain supply-or-pay provisions. Should the Company fail to supply the minimum quantity of natural gas in any one month as specified in the contract, the Company may be liable to pay the vendor an approximately equivalent amount. To date, the Company has supplied at least the minimum quantity each month.

The Company has the following commitments with respect to its office leases:

Years ended March 31 (thousands)	2007	2008	2009	2010	2011	Thereafter
Canada	187	187	197	202	202	471
India	114	107	34	–	–	–
Bangladesh	41	41	17	–	–	–
Thailand	26	34	34	6	–	–
	368	369	282	208	202	471

16. INSURANCE PROCEEDS

The life insurance proceeds relate to a key-man term life insurance policy held by the Company on the life of Robert N. Ohlson, the former President, who died suddenly on November 24, 2004 from natural causes. The Company received the proceeds of $3.3 million during the year ended March 31, 2005.

17. GUARANTEES

(a) During the year ended March 31, 2006 the performance guarantee the Company and its joint-venture partner had provided to the Government of Bangladesh in the amount of US$20 million as specified in the production sharing

agreement for Block 9 was extended to October 15, 2006. The Government of Bangladesh has the right to collect on this guarantee if the Company does not carry out specified geological, geophysical and drilling activities. The Company's portion of the guarantee is US$13.3 million. The Company considers the contingent future payment amount of US$13.3 million to be a reasonable approximation of fair value. There is risk related to the amount of contingent future payment recorded due to fluctuations in foreign exchange rates. The restricted cash balance at March 31, 2006 pertains to this bank guarantee.

See subsequent event note 19. (b).

18. CONTINGENCIES

(a) During the year ended March 31, 2006 the Company was named as a defendant in a lawsuit that has been filed in the state of Texas by a number of plaintiffs who claim to have suffered damages as a result of the uncontrolled releases of natural gas that occurred at the Chattak-2 well in Bangladesh in January and June 2005. Total damages sought are in excess of US$250 million. A court date has been set for July 7, 2006, to hear the Company's pleading for the case to be dismissed due to lack of jurisdiction in the state of Texas.

The Company believes that the outcome of the lawsuit and the associated cost, if any, is not determinable. As such, no amounts have been recorded in these consolidated financial statements.

(b) During the year ended March 31, 2006 a group of petitioners in Bangladesh (the petitioners) filed a writ with the Supreme Court of Bangladesh (the Supreme Court) against various parties including Niko Resources (Bangladesh) Ltd., a subsidiary of the Company. The petitioners are requesting the following of the Supreme Court with respect to the Company:

(i) that the Joint Venture Agreement for the Feni and Chattak be declared null and illegal;

(ii) that the Government realize from the Company compensation for the natural gas lost as a result of the uncontrolled flow problems as well as for damage to the surrounding area;

(iii) that Petrobangla withhold future payments to the Company relating to production from the Feni field (CAD$17.4 million as at March 31, 2006); and

(iv) that all bank accounts of the Company maintained in Bangladesh be frozen.

NOTES

The Company believes that the outcome of the writ with respect to the first two issues is not determinable.

The Company believes that the full amount owed with respect to the Feni field will be collected from the Government. As such, a write-down to this receivable resulting from this writ of petition, has not been recorded in these consolidated financial statements.

The Company's Bangladesh branch has been permitted to make payments to Bangladesh vendors. However, payments to foreign vendors from the Bangladesh branch are not permitted. The Company's foreign vendors are being paid by Niko Resources (Bangladesh) Ltd., which is located in Barbados.

(c) During the quarter ended December 31, 2005 Niko Resources (Bangladesh) Ltd. received a letter from the Government of Bangladesh demanding the following as compensation for the uncontrolled flow problems that occurred in the Chattak field in January and June 2005:

(i) 3 bcf of free natural gas delivered from the Feni field as compensation for the burnt natural gas;

(ii) 5.89 bcf of free natural gas delivered from the Feni field as compensation for the subsurface loss;

(iii) Taka 845,583,973 (CAD$13.8 million) for environmental damages, which is subject to be increased upon further assessment;

(iv) unconditional acceptance that an additional quantity of approximately 45 bcf of natural gas as compensation for further subsurface loss is to be delivered free or an equivalent monetary value is to be provided to the

Government of Bangladesh. Until the actual quantity of natural gas is determined, a bank guarantee in the value of 45 bcf of natural gas shall be provided; and

(v) any other claims that arise from time to time.

With respect to the Government's claims, the Company intends to propose to the Government that the compensation for the uncontrolled flow problems to be resolved through international arbitration through a mutually acceptable forum.

The Company believes that the outcome of the Government's claims and the associated cost to the Company, if any, is not determinable. As such, no amounts have been recorded in these interim consolidated financial statements.

19. SUBSEQUENT EVENTS

(a) The Company commenced operations in Thailand through the acquisition of a 50 percent equity stake in the Fang Block, a production and exploration block. The development phase of this block consists of 8 workovers with a minimum capital commitment of US$10.4 million. The Company must also drill 10 wells with a minimum capital commitment of US$5.9 million on the exploration area of the block.

(b) Export Development Canada provided a performance security guarantee to the Government of Bangladesh in connection with Block 9 on behalf of the Company. Accordingly, the US$13.3 million previously provided by the Company for the performance guarantee was returned.

(c) Export Development Canada provided a performance security guarantee to the Government of India in connection with Block D4 on behalf of the Company. The value of performance security guarantee is US$1.3 million.

Mark Dantzer
Colby Kvisle
Shannon Breeze
Mark Kerpan
Irene Strybosch
Peter Mercier
Ray Dupuis
Murray Hesje

Ivan Kam
Keith Rawlinson
William Hornaday
Joanne Knaus
Cindy Thornton
Edward Sampson
(Missing) Tina Chow

HEAD OFFICE, CANADA

CORPORATE INFORMATION

OFFICERS AND DIRECTORS

Edward S. Sampson
Chairman of the Board, President and
Chief Executive Officer

Mark Dantzer, CMA
Controller

William T. Hornaday, B.SC., P.ENG.
Chief Operating Officer

C. J. (Jim) Cummings, LLB
Director

Walter DeBoni, BASc., MBA., P.ENG.
Director

Robert R. Hobbs, CMA
Director

Conrad P. Kathol, B.SC., P.ENG.
Director

Wendell W. Robinson, BBA, MA, CFA
Director

NOTICE OF ANNUAL MEETING

Shareholders are invited to attend the Company's Annual General Meeting scheduled for Wednesday, August 16, 2006, at 3:00 p.m. (MDT) at the Petroleum Club, 319 - 5th Avenue S.W. Calgary, Alberta. Registered shareholders who are unable to attend are requested to complete and return the proxy form.

ABBREVIATIONS

BAPEX	Bangladesh Petroleum Exploration Co. Ltd.
bcf	billion cubic feet
bcfe	billion cubic feet equivalent
bbl	barrel
bbls	barrels
boe	barrel of oil equivalent (6:1)
boepd	barrel of oil equivalent (6:1) per day
bopd	barrels of oil per day
BTU	British Thermal Unit
GSPC	Gujarat State Petroleum Corporation Ltd.
LBDP	Land Based Drilling Platform
Mcf	thousand cubic feet
mmcf	million cubic feet
mstb	thousand standard tank barrels
m$	thousands of dollars
NGL	natural gas liquids
tcf	trillion cubic feet

All amounts are in Canadian dollars unless otherwise stated.

All barrel of oil equivalent (boe) figures are based on the ratio of 6 Mcf = 1 bbl.

INDIA OFFICE

Niko Resources Ltd.
Landmark Business Centre Racecourse
Baroda, 390 007

BANGLADESH OFFICE

Niko Resources (Bangladesh) Limited
11 Mohakhali C/A
Dhaka, 1212

SOLICITORS

Gowling, LaFleur, Henderson
Calgary, Alberta

REGISTRAR AND TRANSFER AGENT

Computershare
Calgary, Alberta
Toronto, Canada

INVESTOR RELATIONS

Edward S. Sampson
Chairman of the Board, President and
Chief Executive Officer

Suite 4600, 400 – 3rd Avenue SW
Calgary, Alberta T2P 4H2
Tel: (403) 262-1020
Fax: (403) 263-2686
Email: nikocalgary@nikoresources.com
Website: www.nikoresources.com

BANKING INSTITUTIONS

Royal Bank of Canada
Calgary, Alberta

International Finance Corporation
Washington, D.C.

First Caribbean Bank
Christ Church, Barbados

ABN Amro Bank
Citibank
ICICI Limited
Baroda, India

EVALUATION ENGINEERS

Ryder Scott Company
Calgary, Alberta

Gaffney, Cline & Associates
United Kingdom

AUDITORS

KPMG LLP
Calgary, Alberta

LISTING AND TRADING SYMBOL

Toronto Stock Exchange
Symbol: NKO

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www.nikoresources.com

Suite 4600, 400 – 3rd Avenue SW
Calgary, Alberta T2P 4H2
Tel: (403) 262-1020
Fax: (403) 263-2686